EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 16

DATE: Tuesday, May 21, 1991

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

FARR & ASSOCIATES REPORTING INC.

(416) 482-3277

2300 Yonge St., Suite 709 Toronto, Canada M4P 1E4

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, on Tuesday, the 21st day of May, 1991, commencing at 10:00 a.m.

VOLUME 16

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

S T A F F :

MR. M. HARPUR	Board Counsel
MR. R. NUNN	Counsel/Manager, Informations Systems
MS. C. MARTIN	Administrative Coordinator
MS. G. MORRISON	Executive Coordinator

A P P E A R A N C E S

B. CAMPBELL	)	ONTARIO HYDRO
L. FORMUSA	)	
M. PAYNE	)	
J.C. SHEPHERD	)	IPPSO
I. MONDROW	)	
R. WATSON	)	MUNICIPAL ELECTRIC
A. MARK	)	ASSOCIATION
S. COUBAN	)	PROVINCIAL GOVERNMENT
P. MORAN	)	AGENCIES
C. MARLATT	)	NORTH SHORE TRIBAL COUNCIL,
D. ESTRIN	)	UNITED CHIEFS AND COUNCILS OF MANITOULIN, UNION OF ONTARIO INDIANS
D. POCH	)	COALITION OF ENVIRONMENTAL
D. STARKMAN	)	GROUPS
D. ARGUE	)	
T. ROCKINGHAM		MINISTRY OF ENERGY
B. KELSEY	)	NORTHWATCH
L. GREENSPOON	)	
J. RODGER		AMPCO
M. MATTSON		ENERGY PROBE
A. WAFFLE		ENVIRONMENT CANADA
M. CAMPBELL	)	ONTARIO PUBLIC HEALTH
M. IZZARD	)	ASSOCIATON, INTERNATIONAL INSTITUTE OF CONCERN FOR PUBLIC HEALTH
J. PASSMORE	)	SESCI
G. GRENVILLE-WOOD	)	

A P P E A R A N C E S
(Cont'd)

D. ROGERS		ONGA
H. POCH	)	CITY OF TORONTO
J. PARKINSON	)	
R. POWER		CITY OF TORONTO, SOUTH BRUCE ECONOMIC CORP.
S. THOMPSON		ONTARIO FEDERATION OF AGRICULTURE
B. BODNER		CONSUMERS GAS
J. MONGER	)	CAC (ONTARIO)
K. ROSENBERG	)	
C. GATES	)	
W. TRIVETT		RON HUNTER
M. KLIPPENSTEIN		POLLUTION PROBE
N. KLEER	)	NAN/TREATY #3/TEME-AUGAMA
J. OLTHUIS	)	ANISHNABAI AND MOOSE RIVER/
J. CASTRILLI	)	JAMES BAY COALITION
T. HILL		TOWN OF NEWCASTLE
C. REID	)	OMAA
B. ALLISON	)	
E. LOCKERBY		AECL
C. SPOEL	)	CANADIAN VOICE OF WOMEN
U. FRANKLIN	)	FOR PEACE
B. CARR	)	
F. MACKESY		ON HER OWN BEHALF

INDEX of PROCEEDINGS

LIST of EXHIBITS

---Upon commencing at 10:00 a.m.

THE REGISTRAR: This hearing is now in session. Please be seated.

THE CHAIRMAN: Mrs. Formusa.

MRS. FORMUSA: Good morning, Mr. Chairman, Panel.

There are a few housekeeping matters with respect to Panel 2 that I would like to address. The first one is interrogatories. We have had a few that are still trickling in to us, and I think there are perhaps half a dozen that have not been responded to. We are still doing our best to expedite answers for questions assigned to later panels and we hope to be able to have those answers to all the parties sometime this week.

The second matter I would like to address is to ask the parties to provide us with lists of interrogatories and exhibits which they might wish to address to our witness panel in cross-examination. Thus far we have received lists from two parties; and if anyone else has any, we would appreciate them with as much advance notice as possible.

The third matter is in my letter of May 7, I gave a listing of interrogatories and exhibits to which our witnesses might refer in-chief. And I

believe everyone had copies. We sent them out in advance in terms of the interrogatories. Mr. Lucas has a set, and at the front it has a listing of those interrogatories.

Now they are not there to be turned up during the course of evidence-in-chief. The witnesses won't need to refer to them, but they are there as background to some of the overhead materials and they have been referenced as such.

Now, just this morning I handed out an update report. Interrogatory 2.2.22 from Energy Probe had asked for the 1991 update of the "Forecast of Reliability Indices for Use in Corporate Planning Studies," and that was just printed on Friday. I have brought copies here today and they have been inserted into your package. I believe, although I haven't found which one it is in the package, '88 and '89 are already included, so this is 1990.

THE CHAIRMAN: But you say they are there.

MRS. FORMUSA: I believe they are there. I remember photocopying them. But in any event, the two previous versions were provided in response to an interrogatory and I believe that was in the package.

MS. PATTERSON: You said 1991 before.

MRS. FORMUSA: I know. It says 1990. The update that was requested was 1991. I guess they are a year --

MR. TABOREK: It was done in late '90, dated '91.

MRS. FORMUSA: But this is the latest update. It was requested by Energy Probe, and, as I said, it just came out of printing late Friday and we brought it up this morning.

There was a figure that was omitted from Exhibit 87. Again, I have provided copies to Mr. Lucas and copies are available at the front. It was Figure 1 in the appendix. And one of the parties was kind enough to note that it was mentioned in the text, but the actual figure was not reproduced in the text, so copies are available.

We also provided to the parties and to the panel a package of overheads to which the panel will refer in its evidence-in-chief. And perhaps that could be given an exhibit number as well.

THE CHAIRMAN: What exhibit number will that be?

THE REGISTRAR: No. 136, Mr. Chairman.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 136: Package of overheads to be used by Panel 2 in evidence-in-chief.

MRS. FORMUSA: And if parties did not obtain a copy, there are extras at the front table.

I'm sorry, Mr. Lucas, I am not sure we gave an exhibit number to the package of interrogatories with the listing at the front.

THE CHAIRMAN: I don't believe last time we gave an exhibit number for them.

MRS. FORMUSA: We didn't do it. That's fine.

THE CHAIRMAN: Interrogatories don't get exhibit numbers, generally speaking. Am I right about that?

MRS. FORMUSA: All right.

Then without further ado, Panel 2 is ready to begin. I would like to introduce them to you prior to swearing. On my left --

THE CHAIRMAN: Mr. Shepherd?

MR. SHEPHERD: Mr. Chairman, can I deal with something that Mrs. Formusa has just raised, that is, filing a new report?

I guess, I, like many intervenors, have been preparing the cross for Panel 2 and much of my cross deals with reliability. I spent about 30 hours

on the weekend working on the old report of this to prepare my cross-examination. It seems to me that if Ontario Hydro knew that a new report was coming out dealing with this panel, it would have been at least courteous to let us know, rather than having us waste all that time preparing cross on the basis of an old report.

THE CHAIRMAN: It came out on Friday, I think she said; wasn't it?

MR. SHEPHERD: Well, I think she has known about the report for some time; isn't that correct?

MRS. FORMUSA: I wish I could say it was in my personal knowledge that I knew about all updates. The question of updates to reports that have been provided to intervenors and interrogatories was addressed to me in a letter by Mr. Chapman from Energy Probe some time ago.

At the time, we advised him we were unable to, in the interrogatory system, provide automatic updates to reports that had been provided. He had written to me again last week and asked if any of the interrogatories that he had put to Panel 2, whether any of the reports that we had provided, with respect to those interrogatories, had been updated.

This one had and I am providing it in response to that.

THE CHAIRMAN: Is this a whole new report?

MRS. FORMUSA: No, no, it's an update. I have just found the interrogatory in the package that I gave to you, Interrogatory 2.7.40. A number of intervenors have received this report, the earlier versions of it, in response to different interrogatories. But we have used 2.7.40, and it included both the 1988 and the 1989 forecast of reliability indices. It is something that comes out annually and 1990 has just come out.

It was not something that we were filing as an exhibit; it was something that arose during the course of interrogatories. And as I said, we weren't proposing to automatically update all of the responses, but since they did ask last week, that was one that I was able to provide an update to, and it is the latest information with respect to those indices.

MR. SHEPHERD: Mr. Chairman, my simple point is that the intervenors have limited resources and limited ability to deal with cross-examination; and to put us to the time and effort of dealing with an old report when --

THE CHAIRMAN: It is just an update, Mr.

Shepherd. It is not an old report.

MR. SHEPHERD: I haven't looked at the new one to see how much the changes are. But just from a quick glance, it appears there are some substantial changes and I will have to re-do my cross, and I'm concerned about that.

THE CHAIRMAN: Well, the choice is either not to have it at all or to get it when it comes out.

MR. SHEPHERD: Mr. Chairman, what I am asking is that Hydro, if it knows it has an update of a document coming out, advise us when it knows, not when it's printed. That's all I'm asking.

THE CHAIRMAN: All right. Thank you.

MRS. FORMUSA: We will do our best to take that into account. There have been quite a number of interrogatories and quite a number of reports; and as I said, we will do our best.

Unless there are any other matters, I would like to introduce the witness panel to you and perhaps they could be sworn in. On the left is Mr. Ron Taborek from system planning division; and then Mr. David Barrie from power system operations division; Mr. Kenneth Snelson from system planning division; and Ms. Judith Ryan from environment division. They can come forward to be sworn.

RONALD TABOREK,
DAVID BARRIE,
JOHN KENNETH SNELSON,
JUDITH RYAN; Sworn

DIRECT EXAMINATION BY MRS. FORMUSA:

Q. Mr. Snelson, I would like to begin with you, and ask you to give us a brief overview of the matters that will be addressed by this panel.

MR. SNELSON: A. Well, the Demand/Supply Plan has two basic starting points. The first one is the load forecast which has been addressed in Panel 1; and the second one is the existing system, and that is the subject of this panel. ...

[10:13 a.m.] Generally, our evidence will follow the structure of chapters 4 and 5 of Exhibit 3, which is the Plan Report, and it will be divided it into five parts.

Following my brief overview, the first part will be delivered by Mr. Taborek and he will discuss capacity and energy and load characteristics and how that affects planning.

Ms. Ryan will follow with a discussion of the system-wide environmental impacts, and this is an overview of the environmental impacts. It's not a detailed review of each and every option's environmental impact.

Following that, Mr. Barrie will discuss how the existing system is operated, and that, of course, has influence on the future planning.

And then Mr. Taborek will return to talk about reliability, the life of our facilities and their load-meeting capability, and how that can be projected out over time.

And the final piece will be a discussion of the comparison between the load forecast and the load meeting capability of the existing system to define the requirements for new demand and supply options.

Q. You mention that had there were two starting points that were used in the preparation of the Demand/Supply Plan, and I would like you to expand on that.

A. We have here a very simplified figure, which is a simplification of Figure 2-2 of Exhibit 3.

THE CHAIRMAN: What number is this on the overhead?

MR. SNELSON: This would be Figure 1 of Exhibit 36.

The intent of this figure is to show that in the upper right-hand corner the load forecast, and that is the basic load forecast, what the demand would be without Ontario Hydro's demand management programs.

The other starting point I have mentioned is the capability of the existing system which is shown in the bottom left-hand corner, and the difference between those two is the need for new demand or supply resources. And the fact that there is a difference is the reason that we have a Demand/Supply Plan. The whole focus of the plan is to both reduce the load or to increase the supply, so that there is a balance in the middle. And that's a very simplified version which can be met either by demand management or supply or

some combination.

I have behind me a complete version of Figure 2-2, and while this may look a little different to the figure that is in the text, it is identical in all its relationships and all its names to the one that is in the text. Basic load forecast is the starting point in the top right-hand corner and there are demand management options that will reduce it to the primary load forecast, and that was discussed, I believe, in Panel 1, but it will be discussed in more detail in Panel 4.

The existing system is shown on the bottom left-hand corner, and the reserve requirement which defines the capability of the existing system is shown also in the bottom left-hand corner as a reduction from the installed capacity of the existing system. So the requirement in this figure is the difference between the basic load forecast and the capability of the existing system, and that is shown in the right-hand side of the figure.

Now, this figure may be useful to you through the hearing because it helps to keep a number of terms in relationship from one to another, such as demand displacement non-utility generation, which is a demand-reducing option, and purchase non-utility

generation, which is a supply-increasing option. So, this figure may help in keeping some of the terms in better relationship one to another.

MRS. FORMUSA: Q. How do you define the existing system in the Demand/Supply Plan?

MR. SNELSON: A. The existing system is defined as the system as it will be in 1993 after Darlington is completed. The reason for that is that Darlington is nearing completion. It isn't really the subject of this hearing. There have been extensive reviews of Darlington prior to this hearing, and the hearing is primarily and the plan is about the requirements after Darlington. So Darlington is considered to be part of the existing system.

Q. Let's focus on generation for the moment. What are the main characteristics of the different types of generation in the existing system?

A. There are three main types of generation. The first one is hydraulic generation and some of its characteristics are as follows: It generally uses a renewable energy source; you can continue to generate hydraulic energy as long as the rivers continue to flow. The plant usually has a fairly high capital cost - initial cost - to build the plant, but it has quite a low operating cost, because

there are no expensive fuels to buy, such as coal or oil and gas.

The operation of the plant is limited by the availability of water, and it is often advantageous to store the available water for use at peak times when it has the most value. It is always economical to use all of the water that is available, subject to any other constraints that might exist.

The details of our hydraulic generation, both the existing system and what is planned for the future, will be discussed in Panel 6.

The second type of generation is nuclear. In this case, the fuel is a relatively plentiful fuel that has few other uses. Like the hydraulic plants, the capital cost of the plant is quite high, but the operating cost is low, but not as low as hydraulic.

In this case, it's usually economical to use the nuclear plant whenever it's available, but that's not always the case. There are cases where the demand is very low and nuclear plant would be cut back in preference to hydraulic plant.

The details of the nuclear plant, both existing and future, are discussed in Panel 9.

The third type of generation is fossil-fuel generation. In this case there are a

variety of fuels: coal, oil, natural gas. These fuels are generally non-renewable. They are imported into Ontario, and while the cost of construction of the plant is somewhat lower than the other types of generation I have mentioned, the cost of operating the plant is generally higher. And within the fossil-fuel options, there is a range of fuel costs, and hence a range of operating costs, and generally speaking, the lower the fuel cost, the higher the capital cost, and vice versa.

These plants are generally economical for a range of use, from intermediate capacity factor through to peaking type of plant. Most of our existing fossil-fuel plant is pulverized coal plant using a conventional steam cycle. The details of fossil options, both the existing plant and the future, will be discussed in Panel 9.

Q. And with respect to the transmission system, could you describe the general characteristics of that system?

A. I have an overhead here that is Figure 4.1 from Exhibit 3. It is also reproduced as Figure 2 of Exhibit 136. While I recognize that the legend on this figure is probably too small for you to see, it isn't really necessary for this discussion.

The points that I want to make about the bulk electricity system, that's the transmission system, is that it connects together all of the major generating sources right across the province. It connects together all of the major load centres, and, in total, spans a large part of the province, but not all of the province.

In addition, it connects the electrical system in Ontario to neighbouring provinces and states. To the west, we are connecting to Manitoba, to the east we are connected to Quebec, and to the south, we are connected to various U.S. states, and the most significant are Michigan and New York.

And indirectly, through our connections to these other systems, we are connected to most electricity systems in North America, east of the Rocky Mountains. The further point of which it is connected is that from the bulk electricity system, the transmission system that we are looking at, via the distribution system, it connects to most of the electricity end uses in the province.

...

[10:25 a.m.] Now, I have said "most" in a number of cases and that is that it does not include a number of small systems in Northern Ontario which are collectively known as the remote community electricity system, which generally operate separate and independent of the main system that we are considering here.

Q. And what rule does the transmission system play in planning and operating the generation system?

A. We are focusing, as regards to the transmission system, on those aspects of the transmission system that affect how the generation is planned or how the alternatives to generation are planned.

In this case, there are five ways I would like to point out that the transmission system helps in the planning of, and design and operation of, the generation system.

The first one is clearly the most obvious, and that is that, together with the distribution system, it carries the electricity from the generating plants to the final users.

The second point is that the transmission system, by connecting together generating plants, it

now allows a sharing of generation reserve across the system. The integrated system with a transmission system that connects together all of the generating plants has a lower reserve requirement than if it was a number of separate systems without a fully integrated transmission system.

The third point is that generating stations, of some types, tend to have economies of scale. The larger you build them, the smaller is the unit cost of building and operating the generating plant, and an integrated transmission system across the province permits the economies of scale of generation to be realized.

The fourth point is that the transmission system permits economic operation of the generation. In most cases, we are able to run the lowest cost generating plant, or, if it is an environmental constraint, the most environmentally desirable generating plant to meet the load, without having to concern ourselves with whether the generating plant is physically very close to the loads.

So, the generation can be scheduled on a provincial basis to the best advantage and it is the integrated transmission system that permits that to be achieved.

The final point, the fifth point, is that the bulk electricity system, the transmission system, permits mutually beneficial trading of electricity with our neighbours, both in Canada and the United States.

Q. Now, later panels are going to deal with non-utility generation and demand management, and the contributions that those two initiatives will make to the future system, but could you tell us how much non-utility generation is a part of the existing system?

A. At the moment, most of the non-utility generation is load displacement non-utility generation, which is, if you look at the figure, a demand-reducing option. We have a smaller amount of purchase non-utility generation, which is a demand-increasing option, and, in total, these amount to something a little over 5 per cent of our generating capacity in the province.

It is mostly load displacement and has mostly been there for quite some time, but we are beginning to realize the benefits of our non-utility generation program.

Q. How much demand management is currently in place?

A. We have had about 600 megawatts of

interruptible load for several decades. Interruptible load is load which doesn't require generating capacity to support it. It is supplied from the reserve that is provided for the firm loads, and if all of the reserve is required for the firm loads, then the interruptible loads are cut and they receive a lower price for doing that.

There is about 600 megawatts of interruptible load at the time of system peak. There is a larger amount under contract, but you can only interrupt the amount that is actually being taken at the time of system peak.

In addition, we have in recent years established a demand management program to encourage our customers to use less electricity, and up until the end of 1990, the load reduction that has been achieved through that program has an accumulated total of approximately 300 megawatts, and that will be discussed in Panel 4.

Q. Okay. With all of these components that you have mentioned in mind, how do you go about defining the capability of the existing system?

A. Ideally, the generating system should be capable of meeting all of the electricity required by our customers all of the time, and exactly as they

need it, as the load varies on a minute-by-minute, hourly, daily, seasonal and so on, basis. And it would be completely reliable if all of those requirements could be met.

There are other requirements for transmission which I am not discussing and there are also environmental and social requirements, both internally set and externally set, and of course, we try to achieve these objectives at low cost.

Q. And is that the basis on which you design the system?

A. Not entirely. If we were to plan or even attempt to plan a system that was 100 per cent reliable, then it would probably be unacceptable for other reasons. One reason it may not be acceptable is, it would be a very high-cost system.

So, in this panel, we will be discussing the reliability standard and how much reliability we consider to be enough.

We will be using that to set the reliability standard, and to do that, we need to discuss reliability analysis methods. And the whole objective of this is to be able to establish the capability of the existing system to reliably meet load; that is, to meet load with an acceptable level of

reliability. And as I have said before, that is needed to compare with the load forecast.

Q. Finally, is the capability of the existing system constant over the 25-year planning time frame?

A. No. The capability is not constant. The main reason for that is that we do expect some of our plant to be retired over that 25-year period.

In particular, we expect some of our fossil and nuclear plant to reach the end of their useful, economical life, and clearly, in a long-term plan, we have to take that into account in determining our needs for new demand management or new supply options.

Q. Thank you.

Turning now to you, Mr. Taborek, chapters 4 and 5 of Exhibit 3 - that is the Demand/Supply Plan - describe the electricity system in terms of capacity and energy. Could you briefly explain these two terms?

MR. TABOREK: A. Capacity and energy are two important and distinct aspects of the electricity system and an understanding of them is important to formulating the issues and to deriving solutions.

I have prepared a simple illustration of capacity on the top and energy on the bottom. Capacity

is a rate. It is helpful to think of time, and capacity is instantaneous. Now, we usually measure capacity in megawatts in the scale in which we are working.

Energy, by contrast, is the use of capacity over time, so in the upper chart, you see 1,000 megawatts of capacity instantaneously. In the bottom chart, you see 1,000 megawatts of capacity operated for 24 hours to produce 24,000 megawatthours, a figure we use for discussing --

THE CHAIRMAN: There are some problems, I think. Sorry. You are not speaking into your microphone and the people in the back are having some trouble hearing you.

MR. TABOREK: Is this better?

THE CHAIRMAN: Is that better? Okay, all right. Perhaps you could just --

MR. TABOREK: To summarize, capacity is instantaneous. It measures the rate at which electricity is produced, usually measured in megawatts.

Energy, by contrast, is capacity used over time, usually in megawatthours, and it is the total amount of electricity produced. Energy is the area under the curve, and capacity, you will note, has no energy.

MRS. FORMUSA: Q. And that is page 3 of Exhibit 136, the figure you have just referred to?

MR. TABOREK: A. Yes.

Q. Could you tell us what the significance of these two terms is for the planning and operation of the system?

A. Let me give you an analogy. We are a manufacturer, a manufacturer of electricity. An ordinary manufacturer produces various items from raw materials. We produce electricity from the raw materials of coal, uranium and falling water.

...

[10:37 a.m.] The manufacturer has a maximum capacity which depends on how many machines he has and the capacity of each machine. We similarly have a maximum capacity, depending on the number of our generating units and the megawatts of each generating unit.

Q. And what about energy?

A. To extend the analogy, the manufacturer uses his capacity to produce items. The number of items he will produce is usually less than his full production capability if he were to run all his machines flat out, 24 hours a day. The raw materials he uses and the waste he produces is proportional to the number of items he produces.

We similarly operate our capacity to produce megawatthours. Again, the amount of fuel we use, the emissions we produce, are, by and large, related to energy. And again, the amount of energy we produce is less than the total amount we could produce if all machines operated flat out, all the time.

Q. And I would like to add a third term, and that's reliability. How do you define it and how does it relate to capacity and energy?

A. Reliability is giving people the electricity they want when they want it, and here we are different than most other manufacturers. A

manufacturer who is expecting a peak can build a stockpile in advance, he can consider even creating a waiting list and filling the order afterwards.

By contrast, electricity must be produced when it is demanded. This is a phrase that you often see in describing electricity. And it is actually quite a serious phrase because if the capacity is not there to meet the demand, some very destructive effects can occur.

The kinds of effects that can occur is that the generators providing the electricity will gradually slow down under the heavy load. They can get into regions where they are not structurally designed to operate. And they can break, they can destruct at resonant frequencies.

And again, as the amount of electricity generated in a certain region drops off below demand, electricity flows in from other regions over the interconnections, sometimes gradually, sometimes swiftly, and again, there can be disastrous effects on the transmission system. So, the importance of being able to meet demand is more than just a customer convenience; it is a system necessity.

There is an interesting comparison with the phone company who has the mechanism of the busy

signal to defer demands from peak periods. We don't have that luxury. We basically have to provide the electricity when needed, or to cut the load to customers. And what we do in that instance is we generally try to rotate those cuts among different customers so that the inconvenience is shared equitably.

By and large, people are willing to tolerate this kind of thing if it is on a rare occasion and with good reason.

Q. Could you summarize, then, how capacity and energy are used in designing an electricity system?

A. Simply speaking, this figure, page 4 of your exhibit, capacity affects generating unit size and system reliability. Energy affects fuel use and emissions and controls.

Costs are an interesting situation. Capital costs are partly related to providing capacity and partly related to providing low cost energy; whereas operating and maintenance costs and fuel costs are primarily related to energy. And in designing the system, one has to take these two elements and bring them into a proper balance.

Q. I would like to turn now to the

amount of capacity that you have installed on the system and the ability of that capacity to produce energy.

Tell us first, how much capacity is currently on the system?

A. The next figure is page 5 of the exhibit. With the completion of Darlington in 1993, Hydro will have 32,500 megawatts of capacity. To provide some scale, that's about 3,000 megawatts per thousand population. This excludes the generation of Hearn and Keith, two older, smaller stations.

Q. Could you give us a breakdown of that capacity by generation type?

A. Nuclear generation, as you can see on the figure, consists of 14,100 megawatts. That is 43 per cent of the total capacity on the system.

The nuclear units are quite large, as you will see by comparison. They are located in 20 units at five stations. The size of the units ranges from about 500 to 881 megawatts.

The fossil generation is 11,900 megawatts, 37 per cent of the total. These are intermediate units in size, 28 units at 6 stations with unit sizes ranging from about 100 to about 560 megawatts. Three-quarters of the fossil capacity is

coal and one-quarter oil.

The hydraulic capacity is 6,500 megawatts. These are the oldest units on our system. They contribute about 20 per cent of the total and are generally quite small. There are 265 units at 68 stations with unit sizes ranging from less than 1 to about 130 megawatts.

Q. How much energy can that capacity produce?

A. The next chart, page 6 from your exhibit, illustrates our energy production capability. I referred you earlier to perfect production, when every unit operated at full capacity, 24 hours a day. If that were to occur, we would be able to produce about 285-million megawatthours or, for convenience, 285 terawatthours.

Now, that isn't a practical energy production for two primary reasons. One, that we do not have enough water to operate the hydraulic system at full capacity during every hour, and so you will notice that a theoretical maximum of 57 terawatthours is reduced to approximately 36 terawatthours. And again, all of our units require time off for maintenance; sometimes they are forced out for maintenance, or sometimes we take them out for planned

maintenance.

When these two factors are taken into account, the system can produce about 218 terawatthours, assuming, of course, that there are emission controls suitable to that level of operation. And the practical production capability, as we call it, is about 76 per cent of the perfect capability.

Now then we move to the fact that customers do not want all of the energy we can practically produce, and if you introduce the idea of the peaks and valleys and allowance for reserve margin, a typical practical production is about 155 terawatthours. And you will notice that is about 54 per cent of the perfect capability.

If you look down the figure from each these, you will see points made by Ken Snelson as to the economics of the operation of the system. The hydraulic is limited by the amount of water that is available; but given the amount of water, we try to use all of the hydraulic energy that we have because of its low cost.

You can see the nuclear capability that is limited by its maintenance requirements, and again we try and use as much of that as we can, but you will notice there are about 3 terawatthours we are not able

to use because of some drops in demand in peak period below the maximum energy production capability -- excuse me, in off-peak periods, below the maximum energy production of the nuclear units.

And finally, you will see on this figure that the component of our system that changes to meet demand is the fossil system.

And so here you have the reduction in capability due to maintenance requirements, and here is the reduction in capability due to the demand that is made on the system. The fossil component will rise and fall sharply in meeting customer demands.

Q. I would like to turn now to how customers use their electricity and what impact that has on the system. How would you describe customer-use patterns?

A. In Panel 1, it was noted that customers' use of electricity varies over time, and the variations can occur daily, weekly, monthly and annually.

There are two ways of describing customer patterns of customer use. This figure, which is page 7 in your exhibit, illustrates those two methods.

The first on top shows the load chronologically. So, we have here the demand in

megawatts, and in this case, over the 24 hours of the day, and the various demands that are made on the system are just indicated one hour after another, chronologically.

The second re-shuffles this same information. It takes the largest load at about 17 hours and plots it first, and then, sequentially, smaller loads after that, down to the smallest at three o'clock in the morning.

While I have shown you a daily curve, these same kinds of curves can be prepared for weekly, monthly, and I have here a weekly example. This is page 8 of your exhibit. And you will see a series of daily curves and you can see the five weekdays followed by the two weekends. Similarly, shuffling them into order of size, the load duration curve for the same period -- load duration curves tend to work much the same for different periods.

Q. Why do you use both chronological and load duration curves?

A. The chronological curve is the most natural to understand. And it's essential that it be used if the precise time at which something occurs or the precise sequence in which things occur is important. And that's frequently the case in doing

detailed analyses or if you are doing analyses in the operating time frame.

Now, until recently, it was very difficult to deal with the mass of data that was required to do chronological analyses. Recently, however, computers and analytical techniques have advanced to the point where this type of analysis can be used for long term planning as well, if appropriate.

The load duration curve originally came into being because it was a mathematical necessity to be able to analyze a complex power system in the smaller computers of the time and with the methods available at the time. However, having said that, it is also a very useful way of looking at various types of information, much better in many respects than the chronological curve, because what it does is it gives you the percentage of the time that various loads occur.

And so you can say 50 per cent of the time, loads will be above a certain level, et cetera, and that is also very useful in looking at the power system, and I will give you some examples of the use of both of these curves a little later. Both of these will be used frequently during the hearing. ...

[10:50 a.m.] Q. How do these customer-use patterns influence or impact on the electricity system?

A. The peakiness of the customer demand means that we cannot use all of our energy production capability. If I take this same curve I showed you earlier, the previous curve, this is page 9 in your exhibit, and place on it a line showing the amount of capacity that's available in the period, what you can see is that, having provided some reserve, that there is, in effect, a surplus of capacity and a surplus of energy that will be available. And then again, the same thing can be seen on the load duration curve. This gets back to the point made earlier, we are not able to use all of our production capability all of the time because of demands.

Now, we try to make the best of this situation, basically, by scheduling maintenance. If we can, we will schedule maintenance on the weekend where there is the greatest surplus available, or it can be scheduled in other periods, and also we will attempt to export energy from those particular periods of time.

Q. In the planning time frame, what impact do these patterns have on planning for the system?

A. I will just go back to the first

chart that I showed you, which is page 7. There are four important factors in customer planning -- excuse me, in customer-use patterns that affect system planning. These are the maximum point on the curve, the maximum on the load duration, the maximum on the chronological. The minimum point on the curve, the area under the curve, and whether the curve is peaky or it's flat.

Q. Could you go through each of those points on the curve and explain their importance?

A. Now, the maximum points will determine the maximum capacity that the system must have. The minimum points determine the amount of generation that must be run 24 hours a day.

The area under the curve is the energy which, as we have mentioned, influences fuel use, emissions and controls. And the peakiness of the curves influences the characteristics of the demand and supply measures that are useful to the system. In particular, it influences the mix of base and peak types of generation and the types of demand management measures that are useful.

This shows a hypothetical utility, one with a relatively flat demand.

THE CHAIRMAN: This is 136, 10?

MR. TABOREK: Page 10, 136.

One with a relatively flat curve with a high load factor on top and a peaky curve with a low load factor on the bottom.

MRS. FORMUSA: Q. Is a high load factor preferred over a low load factor?

MR. TABOREK: A. No, not really.

Any utility with any kind of load factor will work to flatten it out. That's because it allows the greatest utilization of the resources the utility has. But having said that, customers set the load factor by their demands, their particular demands for power and we try to influence it to the extent we can.

The important thing to note with peakiness is that different measures are required to respond to the different types of curves.

Q. And you mentioned that the type of load factor would have an influence on demand management measures. For instance, could you tell us how the load factor does influence the kind of demand management that would be useful on the system given a particular customer use pattern?

A. If we look at load shifting, first of all, consider the utility with the low load factor. Here is his peak in the late afternoon, to shift load

he only has to shift it a few hours in either direction. By comparison, consider the utility with a high load factor. To get any appreciable amounts of load shifting, you have to shift by about eight hours either way from the peak or you're shifting over a 16-hour peak.

Again, demand management measures, this utility with the peaky curve is only looking for measures that are effective over a few hours. This utility is looking for measures that are effective over 16 hours. Or say if you get measures that are effective for four hours, you, in effect, have to get batches of four to have an effect of one megawatt across the system.

So that this low load utility will generally find more in the way of opportunities for demand management than this utility will.

Q. How does load factor influence the type of hydraulic developments that would be useful?

A. Here again, both utilities will aim their hydraulic developments to the peak period if there are limited amounts of energy. This utility will seek to have a high capacity for a short period of time to use his energy in this peak.

This utility with the same amount of

energy, the same amount of water, would seek to have a lower capacity over a longer period of time. So they will design their hydraulic systems differently.

Q. How does load factor affect reliability?

A. If this utility has --

THE CHAIRMAN: It would be better, rather than say "this utility", to say the "low load factor utility", because I don't think everyone can see the screen.

MR. TABOREK: If the utility with the low load factor has a problem, the problem will occur for a few hours.

If the utility with a high load factor has a problem, the problem can occur for a 16-hour period. So, it's much more critical to have problems if you have a high load factor.

MRS. FORMUSA: Q. How do each of these types of load factors influence the kind of generation that would be added?

MR. TABOREK: A. Here I will shift to the load duration curve. This is page 11 in the exhibit, and it is the same information shown on page 10, but now in load duration fashion.

If we look at the low load factor

utility, and we will ignore for this discussion the reserve requirements, this utility, the low load factor utility, will be looking for approximately 50 per cent of its capacity that will be required to run more than 70 per cent of the time, base load capacity.

The utility with the high load factor, by contrast, would be looking for about 80 per cent of his capacity, able to run 70 per cent of the time or more. It would have a higher mix of base load generation.

The reverse, the low load factor utility might have something like one-third of its generation in peaking generation and this utility, the higher load factor utility something like 10 per cent of its generation in peak types of generation, ignoring reserve margin requirements.

Q. Finally, how does load factor influence both fuel use and emissions?

A. Again, the areas under the curve, the energy requirements, are most conveniently looked at in the load duration curve form, and you will see that, for the same peak load, more fuel is required and more emissions would be produced by the high load factor utility than by the low load factor utility.

Q. How does Ontario Hydro's load factor compare with those of other utilities? Are we peaky or

flat, or how would you describe it?

A. Hydro's load curve is very flat. Our load factor is about 68 per cent. There was a recent survey done of load factors of a hundred utilities and we extracted the load factors and we were only able to find eight U.S. utilities with load factors higher than ours. The other 92 utilities had load factors lower than ours.

We compared ourselves with other Canadian provinces. We found one province with a load factor well above ours, and we were either second or third in a group of about six close runners.

Q. Why would you say that the demand curves of Ontario Hydro and other Canadian utilities are so flat?

A. I think it is partly due to climate, partly due to system size, and I think partly due to our industrial mix.

Ontario stretches a long way from north to south. Most of the province peaks in the winter, some of the large southern cities peak in the summer, Toronto and Windsor, and as a result the curve is flattened over the year.

Secondly, being a large system also tends to flatten loads, in that peaks in one industry,

or in one type of load, will happen at different times and they are not convergent peaks and that helps.

Finally, I believe our industrial demand also tends to flatten the load.

Now, the important point I would really like to make with this is that utilities with a high load factor, like Hydro, will not use the same kinds of measures to meet customers' demand effectively and economically, as will utilities with low load factors. And it is the simple flatness of our load curve that goes a long way to explaining why we place such a large emphasis on base load generation in our planning, and why we look for demand management measures that are effective over a 16-hour period.

Q. I would like to leave Mr. Taborek and turn now to Ms. Ryan.

Mr. Taborek has described customer energy use and requirements. What does meeting these requirements mean to the environment?

MS. RYAN: A. One of the realities of producing and distributing electricity, no matter how it is done, is that there will be an impact on the environment.

Q. What do you include in the term "environment"?

A. Environment, as we defined it, includes the natural system of air, water, land, plants, animals, including human beings and their interaction, social, cultural and economic interaction with the system. So really, it includes both the natural environment and the social environment.

Q. Briefly, could you describe Hydro's policies with respect to the environment?

A. To manage all of its activities affecting the environment so that Ontario receives the greatest overall benefit in the long-term. This requires a balancing of the number of factors, environment is one of them, cost, reliability, safety, would be other factors.

In order to do this, four criteria have been established. One is to meet the law as a minimum, or to do better where we can. An example of where we meet the law is our acid gas emissions.

policy re
Environ.

...

[11:05 a.m.] An example of where we do far better than the law is for our radioactive emissions from our nuclear stations.

The second criterion is to minimize our (2) adverse impact where there are no regulations, and an example of this would be our herbicide reduction program for our rights-of-way maintenance.

The third criterion is to consider offsetting the benefits where we have significant adverse impacts on communities where we have operating facilities, and an example of this would be our (3) community impact agreements with specific communities.

And the fourth is to play a lead role in (4) environmental control technology, development and use, and an example of this would be our intake structure at Darlington which was a new design to minimize our impact on the fish.

Q. And what is considered acceptable environmental performance for Ontario Hydro?

A. Acceptable environmental performance is, as a minimum, meeting the law and doing better where we can. Most of the environment requirments are specified provincially in the Environmental Assessment Act, the Environmental Protection Act and the Ontario Water Resources Act.

In addition to that, nuclear facilities have licensing requirements federally under the Atomic Energy Control Board.

In addition to that, we try to take into account the values of our stakeholders and our customers. It is important to note that the performance of the existing system does not begin with operations. It begins with the planning and the design as evidenced by these hearings, and also, the number of regulatory approvals we have to go through for any new facility. The definition of acceptable environmental performance is changing rapidly these days and we are altering our way of doing business to match.

Q. And how does Hydro manage the environmental performance of the existing system?

A. We have an environmental management system and we have environmental policy. I have already outlined the policy for you.

Environmental management is the responsibility of each line manager and employees throughout the organization. It includes the operating, planning and design decisions that are being made. Our environmental management system has been structured to help line managers carry out their responsibilities appropriately, and, also, to provide

Environ. mgment

checks and balances to make sure that they are.

First, I would like to highlight four of the support systems that are in place to help line 1) managers. The first is Environment Division, which is a small corporate group that was established several years ago to provide a focus to the environment.

THE CHAIRMAN: Now, this is Document 136.12.

MS. RYAN: Yes. I will mention that one just in a second. That is my next point.

The second support system for line managers are the specialist environmental groups throughout the organization, and this figure, which is page 12 of Exhibit 136 - and it is an update of Figure 2.1 in Exhibit 21, which was the 1989 state of the environment - shows that right across the corporation, from corporate relations on the left of the slide through to supply and services on the right, the main 2) areas of our business have special technical expertise in the environmental fields required by those areas to support line managers.

The fourth support system is the 3) Environmental Advisory Panel, which is a group of about nine external experts that were established to provide an external perspective for Ontario Hydro on what is

happening in the environment and how our programs line up, and the fourth support system is a system for identifying environmental issues, prioritizing them and ensuring that one line function has lead rule for coordinating the issue, if it cuts across various branches of the organization.

And now, I would like to highlight two of the checks and balances that are in place to make sure that, in fact, line managers are carrying out their responsibilities with respect to environmental protection.

The first is an environmental audit program, whereby the major operating parts of our business have environmental audits carried out on a regular basis to provide senior management with feedback on how we are doing.

The second check and balance is the environmental sign-off of all Board memoranda for projects which have environmental implications, and this makes sure that the appropriate environmental criteria or considerations have been included before it goes up to the Board for signature.

THE CHAIRMAN: What do you mean by "sign-off"?

MS. RYAN: It means that by Environment

Division has a responsibility to review the memorandum and physically sign it off to say that they have seen it and are in agreement with it or would like the following points considered.

THE CHAIRMAN: Thank you.

MRS. FORMUSA: Q. How does Ontario Hydro monitor and report environmental performance?

1 MS. RYAN: A. Line managers are again responsible for the monitoring and reporting of environmental performance.

The reporting includes both looking at the environmental performance of new facilities and also the ongoing compliance reporting requirement for operating facilities.

First of all, for new facilities, over the last 10 years, each new generating facility has had three years of pre-operational environmental monitoring carried out and, then, three years of post-operational environmental monitoring carried out to see that the assumptions made at the design stage were, in fact, correct, and to look for any environmental implications which were not expected and to mitigate them.

The second, the ongoing environmental monitoring is the responsibility of, for example, the

2 station manager at nuclear stations. Each station

manager is responsible for making sure that appropriate monitoring equipment for monitoring radioactive emissions are in place, are maintained, are calibrated, and that the data is verified and reported to the regulatory authorities.

(3

The annual State of The Environment Report was prepared to provide an overview of Ontario Hydro's environmental performance for the Board of Directors. Both the 1988 and 1989, reports were filed as exhibits for these hearings, and the 1990 report is now in preparation and should be ready for issue in early July.

The reports compile environmental performance, how we are doing, and also identify areas where we need improvement and give some examples of what types of issues we expect to be coming up in the future.

Q. What categories of performance are reported?

A. We generally monitor and report according to the categories of air, water, material and waste management, and land management. And the State of the Environment Report has, in fact, reported in each of these areas.

Q. I would like to take each of these

categories in turn, and first ask you about the air characteristics of the existing system.

A. The ones giving the most emphasis for the existing system are acid gas emissions, radioactive emissions, and particulate emissions as visible emissions.

Others of lesser importance would be carbon dioxide emissions, particulate emissions as fugitive dust from our coal piles and ash piles, trace element and chemical emissions, and hydrogen sulphide emissions.

Q. Okay. Then focusing on the first three types of air emissions, could you begin, first, by telling us about the acid gas emissions?

A. Acid gas which leads to acid rain and acid deposition is made up of sulphur dioxide emissions and nitric oxide emissions, and acid gases are emitted from our fossil stations.

The sulphur dioxide comes from the sulphur in the fuel and so is directly related to the amount of generation. The nitric oxide comes from the nitrogen in fuel and the nitrogen in the combustion air, and so is related to boiler type and to combustion conditions.

Ontario Hydro produces about 20 per cent

of the total acid gas emissions in Ontario and about 1 per cent in North America.

Q. Currently, what limitations are there with respect to acid gas emissions?

A. Ontario Regulation 281/87 under the Environmental Protection Act limits Ontario Hydro's total acid gas emissions in a stepped fashion, as shown in this chart, which is page 13 of Exhibit 136, and it is taken from Figure 4.10 in Exhibit 3.

As you can see, our acid gas emissions were capped, first in 1987 at 430,000 tonnes, and stepped down to 280,000 tonnes in 1990, and will step down again, the cap will step down again in 1994, to 215,000 tonnes.

Sulphur dioxide alone is also limited to 370,000 tonnes, then down to 240,000 90, and down to 175,000 94, in the same steps as the total acid gas.

Nitric oxide emissions alone are not limited.

Q. So, they form part of the total?

A. Yes.

Q. Okay. Could you review the figures for Hydro's acid gas emissions, the actuals?

A. Yes. This figure, which is page 13 in your exhibit hand-out.

Q. That is page 14.

THE CHAIRMAN: Fourteen?

MS. RYAN: I'm sorry. Page 14 shows our actual historical acid gas emissions. The hatched part is sulphur dioxide; the clear part is nitric oxide and the total make our total acid gas emissions. And you can see that we have complied for each year where the regulatory limit has been in place.

Since our emissions in the early 1980s were around 500,000 tonnes, you can see that getting down to 215,000 tonnes in 1994 is a significant reduction, about 60 per cent.

MRS. FORMUSA: Q. Okay. And what measures --

THE CHAIRMAN: Are you making the SO(2) limits, as well?

MS. RYAN: Yes. We have met the SO(2) cap, as well.

MRS. FORMUSA: Q. What measures has Hydro undertaken in order to reduce these emissions?

MS. RYAN: A. To date, Ontario Hydro has reduced the sulphur content of the fuel that it uses, and it has reduced the amount that it uses its fossil generation.

Fuel sulphur levels have been reduced

from about 1.8 per cent sulphur fuel in the early '80s through to under 1 per cent last year.

As you can see from this figure, which is page 14 -- 15, sorry, page 15, and it is an update of Figure 10.1 in Exhibit 21.

This reduction alone has reduced our sulphur dioxide emissions by about half or almost 200,000 tonnes.

Two scrubbers are currently under construction at Lambton Generating Station to be in operation by 1994, and those scrubbers will remove 90 per cent of the sulphur dioxide from the stack gases of those units.

In addition to that, we are carrying out studies to see what control equipment would be feasible for reducing our nitric oxide emissions, as well.

Q. Now, you mentioned earlier that the nitric oxides are not regulated separately from sulphur dioxide emissions. Do you expect this to change?

A. Yes. It is likely to change. Because of the elevated groundlevel ozone in the summer or summer smog, the brown air that you see in August, especially in the Windsor-Quebec corridor, initiatives are underway to reduce nitric oxide emissions because it is a precursor to groundlevel ozone.

forerunner

An agreement in principle was reached between the federal government and the provincial government for NOX emission reductions. We do not yet know the timing of the reductions or exactly what our emission limits will be, but we expect that we will have emission reduction targets by November of this year.

Q. How do you go about determining what the actual acid gas concentrations are around your fossil stations?

A. Ontario Hydro monitors sulphur dioxide in the air around each of its fossil stations typically at groundlevel, about 5 to 20 kilometres away from the station.

Sulphur dioxide, as I mentioned, is one of the main components of acid gas. Such monitoring has been carried out around our stations since the early 1970s, and the data from these measurements measure the sulphur dioxide from all sources, not just Ontario Hydro's stations.

The Ontario Ministry of the Environment have set criteria under the Environmental Protection Act to protect the vegetation and human health, and there are criteria for hourly, daily, and annual limits.

In 1990, for the first time since we started monitoring sulphur dioxide, none of our monitors measured any data above these criteria, which is a significant improvement over some of the previous years. And we feel that our reduced sulphur and fuel and reduced use of our fossil stations contributed to this improvement.

...

[11:20 a.m.] Q. I would like to turn back now to the second type of air emission that you mentioned earlier. Could you describe what you mean by visible emission?

A. Visible emissions are the particulate emissions from our fossil stations that we can see. Most of the particulate matter formed during combustion is removed by the control equipment or precipitators, but a very small amount is emitted as visible emissions. This should not be confused with the steam plume that you can see in winter.

Q. What requirements must Hydro observe with respect to such emissions?

A. Visible emission requirements are specified in the Environmental Protection Act, Regulation 308, that is opacity, and are measured by Ministry of the Environment trained observers or really calibrated eyeballs.

Visible emissions are to be controlled to a limit, an opacity of 20 per cent with higher levels allowed for short periods of time. Opacity is a continuum from zero per cent, which you can't see at all and allows the full transmission of light, through to 100 per cent which would be highly visible and not allow the passage of light at all.

Q. What levels of these visible

emissions have been observed from Hydro facilities?

A. Ontario Hydro has monitors which continuously measure stack opacity. This allows us to measure it, independent of time of day or weather conditions, and also allows us to have the measurement in control room for the operators. Our performance target is 20 per cent opacity as measured by these monitors.

In 1990, visible emissions from Ontario Hydro's coal-fired station was over the 20 per cent opacity limit for 2.6 per cent of the time. As you can see in this figure, which is page 16 of the handout exhibit, this was an improvement over the 3.6 per cent in 1989 and the 7.6 per cent in 1988.

The control requirements for visible emissions have increased because of our decrease in precipitator performance. This deterioration has been caused by a number of factors; one of them is the aging of the equipment, and the other is the increased use of low sulphur coal.

Q. So what measures are being pursued by Hydro in order to reduce these emissions?

A. When visible emissions approach the limit, the short-term solution is to derate or cut back the unit until visible emissions are again acceptable.

The longer term solution includes such control actions as rehabilitating the precipitators and installing flue gas condition equipment to allow them to remove particulates sufficiently while burning low sulphur coal.

(2)
(3)
(3)

Q. Finally, with respect to the third area of air emission, and that is radioactive emissions, could you describe those emissions and how they are regulated?

A. Radioactive emissions to air from our nuclear stations include particulate, noble gas tritium, and iodine 131. Each of these emissions can be produced as part of our normal operations at the station. Each of these is regulated separately by the Atomic Energy Control Board for each nuclear facility as part of its operating licence.

Q. And how are these emission limits determined?

A. These emission limits are derived or back-calculated to ensure that the recommended public dose limit is met. It should be noted, in this calculation, both emissions to air and emissions to water are taken into account. Public dose limits are based on international standards which have been adopted by the Atomic Energy Control Board.

The pathways by which our radioactive emissions from our nuclear facilities can reach the public are analyzed. And if you look at this figure, which is page 17 of the handout exhibit, it shows that such pathways from the station to people could include drinking water, inhalation, consumption of milk. And using the information from these pathways and making conservative assumptions, specific emission limits for each emission are set for each station.

In the early 1970s, Ontario Hydro adopted an operating target for radioactive emissions of 1 per cent of the regulatory limit for each of the radioactive emissions, and our stations are operated to meet this 1 per cent operating target.

Q. What results have you observed from the monitoring of these emissions?

A. Ontario Hydro monitors both its water effluence and its exhaust gases for radioactive emissions to the environment. It is done for two reasons: one, to allow additional control if the emissions are too high; and number two, to monitor performance so that it can be reported to the regulatory authorities.

Over the past five years, each Ontario Hydro facility has met the operating target of less

than 1 per cent of the regulatory limit on an annual average basis. The regulatory limits have never been exceeded.

Q. Finally, can you give us a little more detail with respect to your monitoring activities, in the environment surrounding Hydro's nuclear facilities.

A. In addition to monitoring emissions on each site, environmental monitoring is carried out in the environment around each of our nuclear facilities. Sampling includes such things as air, rainwater, drinking water, milk, all of which are pathways by which our radioactive emissions could reach the public.

Samples are analyzed for the radioactive species which could be produced from our stations. These programs are in compliance with the operating licences for each facility, but it should be noted that the monitoring was put in place before, in fact, they were licenced conditions.

The 1989 results, which were compiled by an independent consultant, indicated that the dose to the public as a result of living near one of our nuclear facilities was less than 1 per cent of the regulated limit. The results of these programs are

compared to control sites, to historical data, and to expected data based on emissions to make sure that there are no -- to identify any trends or anomalies in the data.

The dose from station emissions to a member of the public living at the boundary is a small fraction, about 1 to 2 per cent, of what they receive from natural background radiation. And this figure, which is page 18 of your exhibit, shows what a person living around the station boundary would receive on an annual basis. The top bar is what any one of us would get from natural radiation. Medical exposures include chest x-rays, dental x-rays, down to the bottom which shows what the member of the public would get specifically from emissions from a nuclear facility.

Q. I was going to turn now to the second category which is water. But I wondered if this was the time when you took your morning break.

THE CHAIRMAN: This is probably the time to take the morning break. We will take fifteen minutes.

THE REGISTRAR: We will recess for 15 minutes.

---Recess at 11:30 a.m.

---On resuming at 11:47 a.m.

THE REGISTRAR: This hearing is again in session. Please be seated.

MRS. FORMUSA: Let's turn now to the second category of environmental performance that you said you monitored, and that's water.

Q. What are the main water characteristics of the existing system?

MS. RYAN: A. These include thermal effluence, radioactive effluence, chemical effluence, fish impingement and mercury in reservoirs.

Q. Could you first explain the concern with respect to mercury in hydroelectric station reservoirs?

A. In some hydroelectric developments
1
outside Ontario, reservoir flooding has resulted in increased concentrations of methyl mercury in fish, both in the reservoir and downstream of the reservoir. This is a concern to local residents who may consume large quantities of the fish.

Q. What is Ontario Hydro doing about this?

A. In Ontario Hydro's existing reservoirs, the concentrations of mercury in fish appear to be within the range normally found in natural water bodies. However, we recognize the concerns and

we are participating in studies for future hydroelectric developments.

Research programs have been initiated to understand the cycle of mercury in reservoirs, to predict mercury levels, and to prevent or mitigate the build-up of mercury in the future.

(2)

Q. What about chemical effluence in water?

A. MISA, the Municipal Industrial Strategy for Abatement, which is a Ministry of the Environment initiative, has been set up to virtually eliminate the emissions of persistent toxics into our waterways. We are currently monitoring our effluence at each of our fossil-fuel stations and at six hydraulic stations under a regulation for MISA.

We expect a regulation in '92 or '93 specifying effluent limits for each of these stations. We don't yet know what the exact timing or the levels will be.

Q. no reg. yet? just monitoring?

Q. And the third category that you mentioned was material and waste management. What are the material and waste management characteristics of the existing system?

(3)

A, B, C, D.

A. These include nuclear-used fuel, radioactive waste, ash, and PCBs or polychlorinated

biphenyls.

Q. I would like to deal first with nuclear-used fuel. How does Ontario Hydro manage this material?

A. Used fuel is a byproduct of nuclear generation. After about one and a half years of being in the reactor, the fuel bundles are removed from the reactor by remote control machine and put in storage containers for storage in water-filled bays. These provide cooling and shielding for the heat and radiation produced by the used fuel bundles. Presently, all of the storage of our used fuel is in water-filled bays.

Storage of used fuel at nuclear stations is regulated by the Atomic Energy Control Board as part of the operating licence. Representatives of the AECB are on-site to monitor performance with respect to the operating conditions. The AECB has the authority to revoke our operating licence should we not be meeting any of the requirements for the storage of used fuel.

Ontario Hydro is supporting the development of the Canadian disposal concept for used fuel, which is co-ordinated by AECL, Atomic Energy of Canada Limited, under the Canadian Nuclear Used Fuel Management Program. Panel 9 will be providing more

Q Panel 9

detail of used fuel storage units in its presentations.

Q. What about radioactive solid waste that's produced at nuclear facilities?

A. Radioactive solid wastes are materials which have become radioactive through use in one of our nuclear facilities. Page 19 of the exhibit handout, and the source of this data was Interrogatory 2.9.4, shows the production level of solid radioactive waste at all of our nuclear facilities over the last five years.

Radioactive wastes are currently maintained in long-term storage areas which are engineered to contain the waste and where the waste can

Q. what is this mean.

be retrieved for eventual disposal. Most of the solid

Final ?

waste from our facilities is stored at the radioactive waste operation site at our Bruce development.

Emission limits for waste storage have been set by the Atomic Energy Control Board, and again Ontario Hydro emissions are generally less than 1 per cent of these limits on an annual average basis. We carry out monitoring of the surface and subsurface drainage to ensure that in fact these limits are being met.

Our efforts have been increased over the last couple years to reduce the amount of radioactive

waste being produced at our facilities, especially the low level waste which makes up about 98 per cent of the solid waste which is produced. A target of a 50 per cent reduction in the amount of waste being produced annually has been set for the year 2000, and a corporate plan is currently being prepared for the long-term management of radioactive waste, and again Panel 9 will address future plans in more detail.

Q. The third type of waste that you mentioned was coal ash. How much coal ash does Hydro currently produce?

...

[11:55 a.m.] A. Ontario Hydro fossil-fueled stations produced about 900,000 tonnes of coal ash in 1990. About 80 per cent of this was flyash which is collected from the stack gases and the remainder was bottom ash.

This figure, which is page 20 in your handout, shows the amount of coal ash produced over the last five years. And in fact, it's quite closely tied to generation at our fossil station, so you can see the drop in 1990 was due to the low use of fossil stations during that year.

Q. What happens to this ash?

A. Most of the bottom ash was used on station sites or sold for such purposes as road construction. Flyash can be used for cement manufacture and for mine backfilling. In 1990, about 22 per cent of all of our ash was in fact used or sold.

All stations, except for Lakeview generating station, have on-site storage of unused ash, and in 1990, all of Lakeview's ash was sold. The unused ash from the other stations was stored in the designated area on each site. Ontario Hydro's strategy for ash management is emphasized in utilization for the future.

Q. Lastly, how is Ontario Hydro managing its PCBs?

A. The handling and storage of PCBs and PCB waste is strictly regulated under the Ontario Environmental Protection Act, The Canadian Environmental Projection Act and the Transportation of Dangerous Goods Act.

Ontario Hydro has policies and procedures in place for the safe handling, use and storage of PCBs. In addition to that, we have a program underway to eliminate PCB and PCB-contaminated mineral oil from our in-service equipment. We are in the process of eliminating lower level PCBs through the use of mobile processing unit which can decontaminate the PCB contaminated oil. We are also participating in studies looking at destruction facilities for PCBs and solid PCB waste.

This figure shows you that to the end of the 1990 we have decontaminated the 2.6-million litres of PCB contaminated oil. You can see from '87 through '90, the amount in storage has gone up as we have taken it out of facilities and the amount in equipment has come down at the same time.

But the important thing is that the black bar, which is the total amount of PCB contaminated oil, has come down over time, as, in fact, we have used this process to decontaminate the mineral oil and the oil is

then available for reuse.

Q. And the page you have just referred to is page 21 in Exhibit 136?

A. Yes.

Q. Finally, the last category that you monitor is land use. Could you describe the land-use impacts or characteristics of the existing system?

A. The land-use characteristics of the existing system include secondary land use, right-of-way management and wildlife habitat.

Q. Does Ontario Hydro also consider the social environment with respect to land impacts?

A. Yes, it does. Ontario Hydro has a responsibility to address the effects of its activity on the social and cultural environment, as much as on the natural environment.

The social environment includes both the socio-economic effects such as regional employment, regional economic development and community impacts, as well as the societal considerations of social acceptance and lifestyle.

There are a number of aspects of our existing operation that have caused public concern. One is the potential human health affects associated with electric and magnetic fields. At present, the

consensus of the scientific community is that health risk has not been established. There is, however, general agreement that there is a need for more research and Ontario Hydro is participating in such research in cooperation with other organizations.

Another concern is about the potential effects on public health of the low levels of radioactive emissions from our nuclear stations. Even though emissions from our nuclear stations contribute only a small portion of the dose that people already receive from natural background, we are participating in health studies to address these concerns.

Ontario Hydro works with communities to resolve social issues associated with its operating facilities, it provides community impact grants for some communities, and it carries out socio-economic impact analyses as part of the environmental assessment process for future facilities.

The impacts of specific technologies will be dealt with in the options panels.

Q. Thank you, Ms. Ryan.

Mr. Barrie, Mr. Snelson described earlier the broad characteristics of the power system in terms of its generation and transmission components. Could you tell us how all of this is managed on a day-to-day

basis?

MR. BARRIE: A. The day-to-day control of the interconnected power system is done by operaters at the system control centre which is located in Mississauga. The operators at the control centre coordinate the actions of operators situated at the generating and transmission stations throughout Ontario. This is an ongoing task, 365 days a year, 24 hours a day.

A simplified overview of what is involved is shown here. This is Exhibit 136, page 22.

The overall objective is to provide a continuous supply of power to customers. It must be done safely and delivered within a specified voltage and frequency limits. It must be done at minimum cost and it must respect the environment.

Essentially, what is shown here are two functions, the production of electricity and the delivery to customers.

First, the production function, which is shown on the left. The control centre coordinates the output from the hydraulic fossil and nuclear power stations, they integrate into that the output from the non-utility generation. They also discuss with interconnected utilities, the bottom there, purchases

and sales. So, that overall function there is all aimed the optimizing the production of electricity.

The delivery function I show to the right. The delivery function is essentially involved in ensuring the integrity of the transmission network. The operators at the control centre continuously monitor the status of the integrated transmission network and instruct the operators at the transmission stations to do what whatever is required to ensure integrity. They do that through the regional operating centres. I have shown one there; there are actually five situated at various locations around the province.

So, as you can see, the system control is centre, although it doesn't generate one megawatt of electricity itself, is in fact the nerve centre of the day-to-day operations.

Q. Does the centre oversee the operation of the entire power system?

A. The interconnected system comprises of three components, and I show them here on Exhibit 136, page 23.

1 The three components are the generation, which is the Hydro fossil and nuclear plant, the 2 transmission, which is high voltage lines at 500-, 230- or 115,000 volts, which essentially do two functions:

They interconnect the generating stations and they allow for bulk transfer of power from the generating stations to the bulk supply points.

The bulk supply point is a transformer station which transforms the voltage down to something like 44,000 volts or below, where the third function, the distribution function, takes over from the bulk supply points to the customers. I will say more on the distribution later, but moving back to the generation and transmission.

The generation and transmission, taken together, form an integrated whole and they must be operated as such. We call the integrated system of generation and transmission the bulk electricity system, and the control centre overseas, the operation of the whole bulk electricity system.

In contrast, the nature of the distribution system, and as the name suggests, it is distributed across the province and there is no need for it to be operated as an integrated whole.

So, looking at the distribution system, there are really three modes of delivery to customers: The first of these I show at the bottom of this overhead, the direct customers, who, as the name suggests, take their power directly from the bulk

supply points. There are 113 such large industrial customers, who take approximately 17 per cent of the total load.

The second mode of delivery, and by far the largest, are the municipal utilities. They act as wholesalers; they buy power from Ontario Hydro and resell it to customers. There are some 315 municipal utilities and they sell about 70 per cent of the total load.

In those parts of the province where there is no municipal utility, Ontario Hydro has its own retail facilities. We call the Ontario Hydro's own retail facilities the distribution electricity system, and we define it as any equipment that Ontario Hydro has that is operating at less than 50,000 volts. About 13 per cent of the power is delivered through Ontario Hydro's retail system.

So, in summary, the control centre controls the bulk system, the generation and transmission; it does not control the distribution.

Q. Mr. Taborek described how the demand for power varies throughout the day.

How do the operators at the system control centre arrange the generation in order to meet this variable demand?

A. Well, as Mr. Taborek mentioned, we can't store electricity. We have to ensure at all times that we have sufficient generation on line, and, by that I mean, connected to the grid system, to meet the demand for power. And moreover, the generation must be capable of being varied to meet the minute-to-minute variations in power demand.

Now, ensuring that, within the operating time frame, there are many interrelated and complex tasks. Before I go on, I would like to clarify what I mean by the phrase "operating time frame."

As operators, we are charged with making the best use of the existing system. So if we look ahead at some future situation or problem, if there is insufficient lead time to build new facilities to address that problem, it must be met by existing facilities, we would define that as an operating problem. So anything that falls into that category, we would call "fell into the operating time frame," solving a problem using existing facilities.

Now, in some cases that can mean looking several years ahead; in some cases, we look up to five years ahead, but, in general, we are looking one or two years ahead. That is the normal emphasis as operators we place.

So, if I define that as the operating time frame, the next year or two, then within that, it is possible to subdivide the operating time frame into two categories, what I will call operational planning and real time operations.

Operational planning involves looking days, weeks or months ahead, the kind of thing involved in coordinating major outages of transmission or generation equipment, or ordering fuel for generating stations. That kind of activity falls within the operating time frame, but is what I would call operational planning.

The second real time operation is the much more immediate concern, how are we operating today or the next 24 hours, say, and that's what I would like to focus on now, because that's the responsibility of the control centre.

So in preparation for the next day, staff prepare a generation schedule plan. The plan outlines how the generation, which is expected to be available the following day, will be scheduled on to meet the expected demand.

In formulating the plan, the staff have four objectives: First, to minimize overall production costs; secondly, to respect internal system = p2781

constraints; thirdly, to respect the environmental concerns, and fourthly, to ensure that we have reliable supplies to customers.

Q. If we take each of these in turn, firstly, how do you minimize costs?

...

[12:10 p.m.] A. The plan minimizes costs by optimizing the use of each type of generation. Normally, the schedule would look something like this overhead here, which is Exhibit 136, page 24.

Mr. Snelson mentioned the different kinds of generation we have and this shows how that generation is used on a daily basis.

I talked about base load plan, the cheapest generation we have available. Because it is cheapest, we would like to use it as much as possible, so we schedule it on for 24 hours and it is usually flat, constant load throughout the 24-hour period.

The type of base generation we have is nuclear generation and most of our hydraulic; that is, any hydraulic we have where there is sufficient water to run it for 24 hours.

The second category is intermediate or medium cost generation, which would typically be our coal-fired generating plant. Normally, that would be on for some 16 hours throughout the day. On this particular day, you see there was some fossil generation, was on 24 hours. I will say a little more on that later.

Thirdly, peaking generation. Now, there are two kinds of peaking generation. First, there is

the hydraulic plant where there is insufficient water to run for 24 hours. We will then use it at time of system peak. The other kind of peaking plant is our most expensive plant, our oil-fired generation and our combustion turbine units. Because it is very expensive, we try to minimize the operation.

As I said, this was one particular day. It was actually February the 12th, 1991, this particular day, which sort of explains why the different generation is at the levels it is at.

At other times of the year, the base load generation could meet the whole 24 hours and there would be no need for the intermediate generation to be on, at all overnight. So, the relative magnitudes of the three different kinds does vary throughout the year.

This schedule is produced by simulating the use of the expected available generation and it is done as follows: We have first scheduled on the nuclear and the hydraulic, the baseload hydraulic, a constant band, as I explained.

We will also factor into this the base load non-utility generation. On this particular day, there was about 100 megawatts of base load non-utility generation. We would expect to have more of that in

future years, but that must be factored in at this point.

The next thing we do is to utilize the peaking hydraulic to the maximum extent possible to peak shave. That means generating as much as possible when demand is highest and it has the effect of shaving the peak off the demand curve, and what is left in the middle is the demand to be met by the fossil. This is fairly flat through most of the day, as you can see from this overhead.

By maximizing the cheapest and by peak shaving as much as possible, the resulting-out requirement from the fossil is steady and that has the effect of minimizing overall production costs.

Q. The second objective that you mentioned was with respect to internal system limitations. Could you describe how these are taken into account in the generation plans?

A. We do have limitations on both the generation and transmission equipment. On the generation, if you again refer to the overhead I have up there --

Q. That is page 24?

A. Page 24. On the generation, as we schedule on the generation, we must respect certain

limitations, such as if we have plant on-load, there are certain minimum loads which the plant must have, otherwise it is unsafe to operate.

There are certain maximum rates at which plant can pick up load in the morning, so that must be respected in the schedule, and when we shut plant down, we must leave it down for for certain minimum shut-down times. These are the kinds of constraints I mean by "generation constraints." They all constrain on how closely we can following the load curve.

In terms of transmission constraints, in an ideal system, demand anywhere in the province could be met by any generation; however, in the real world, practical considerations are that we have insufficient transmission capability to transfer power to the load.

We have what we call "transmission bottlenecks" in the system, which are often caused by the delay in building new lines.

Operationally, we handle these transmission bottlenecks by defining certain key interfaces on the transmission system and the operators at the control centre monitor closely the flows on those transmission interfaces to ensure that the maximum transfers are not exceeded. So, this can effect the amount of generation that is usable from a

certain station.

Q. And how significant are these transmission bottlenecks that you mentioned?

A. The significance varies depending on the generation configuration and the transmission configuration.

I think to illustrate, I would like to take a specific example, probably the most significant transmission constraint we have experienced in the last 10 years, and that is the inadequacy of the transmission facilities out of the Bruce Generating Complex.

A simplified system diagram of the Bruce area is shown here, Exhibit 136, page 25. This is the system as it existed last year. The two thicker lines coming from Bruce and ending at Milton Transformer Station, represent the two 500 kV lines or the main means of getting power out of Bruce.

The thinner lines going to Owen Sound, Orangeville and Stratford represent 230 kV lines. The limit we defined is shown by the heavy black dotted line where we cut across all of those transmission lines emanating from Bruce, and we call that interface the Flow Away from the Bruce Complex, FABC.

The maximum flow that FABC can reach is

5,400 megawatts. The maximum generation available at Bruce, with all units in service, is 6,500 megawatts.

So, on the generation schedule, we could only use 5,400 megawatts, and, in effect, 1,100 megawatts was bottled. Now, the actual bottling amount depends on the transmission and generation available at any particular time and it varies constantly.

In the latter part of the 1980s, there was significant amounts of generation bottled at Bruce because of this particular transmission inadequacy. The situation was largely rectified in November 1990, when the transmission was reinforced and, in fact, a new double-circuit 500 kV line was built from Bruce down to the London area.

We are not now experiencing any bottling at Bruce and will not expect to have any bottling with all transmission in service. And, in fact, in general, although we will continue to closely monitor, operationally, transmission interfaces, we cannot foresee significant bottling anywhere in the province in the immediate future.

NB Now no bottling at Bruce

Q. I would like to move on now to the other objective you mentioned, namely, the environmental citizenship considerations. Could you elaborate on how these affect day-to-day operations?

A. Environmental considerations affect operations in that they sometimes cause us to move away from a scheduling program based purely on economics. Throughout Ontario Hydro's operations, there are many, many examples of this taking place and some are decades old, where others have come to prominence more recently.

Q. Could you give us some examples?

A. Ms. Ryan mentioned the acid gas regulations and explained how we were required to reduce acid gas emissions by stages over a number of years. I would like to elaborate on what that meant to us operationally.

The trend towards burning lower sulphur coal was not without problems. Our plant, our generating plant, was not designed or built to burn low sulphur coal. Specifically, the precipitators, which is the equipment which removes flyash from the flue gases, does not operate as well with low sulphur coal as it does with medium or higher sulphur coal.

This was known and we installed special flue gas conditionning equipment to recitify the problem, but we were forced in 1990 to lower output because of the opacity problems that Ms. Ryan mentioned. In fact, we had to derate the plant.

remove

In 1990, we changed the order in which we scheduled planning, that the fossil plant that I mentioned, the intermediate plant, has an order of operation based on cost. We, obviously, like to run our cheapest plant most, but we did all alter this in 1990, causing the plant which had the highest contribution to acid gas to run less, and that which contributed least to run more.

In 1990, again, despite all these measures, the projection for the acid gas was still too high. This was largely because of poor performance by our nuclear plant, which was requiring the fossil plant to run more than we had expected, so we had to take further measures and we curtailed all sales to our interconnected utilities and we increased purchases. Using all these actions, we were able to reduce the emissions below those stipulated in the regulations.

So, as you see, in 1990, respecting the acid gas, regulations had a threefold impact on the schedule. It derated the capacity, it changed the order, and it changed our purchase and sales strategy. So, that is a fairly recent example, over the last few years, of an environmental constraint affecting the way we operate.

inf. bec of acid gas reg. but bec of nuke poor performance

I think another example I would like to

quote is a very old one, the way we operate a hydraulic plant. As we explained, minimizing cost involves using some hydraulic plant to peak shave, which involves storing water most of the day and using it at peak times. This causes variations in the reservoir levels and variations in the downstream flows.

If we identify adverse effects of this kind of operation, we may modify our operations to mitigate these adverse effects. I will give a few examples, but there are many, many more.

We undertake and maintain minimum flows and levels for pickerel and trout spawning on the Mattagami/Mississagi/Nipigon. We restrict water levels for nesting for ducks on the Frederickhouse and muskrats on the Kamaniskeg. We maintain flows and restrict fluctuations for leisure activities all over the province. We maintain minimum flows during drought conditions to maintain town water supplies, Town of Timmins, Mattagami, and Pembroke, River Ottawa, and we maintain specified water levels for wild rice cultivation on the English and Winnipeg Rivers.

There are many, many more, and the reasons are very varied, but as operators, they all really translate to three constraints upon us: Maximum and minimum flows, maximum and minimum reservoir

levels, and the magnitude and rate of fluctuations.

All of these constraints can tend to push us away from least-cost operation. Some of these are mandated by water authorities. Others are requests, often from the public, and we will strive to accommodate them unless there is undue adverse effect on the bulk electricity system or on other watershed users.

Q. With respect to this daily generation plan that we have been talking about, how do reliability considerations affect the plan?

A. The plan must be sufficiently robust that it can ensure that we can cope with uncertainty, because rarely will the actual situation the following day be exactly what was forecast?

There will be unforeseen events take place and the plan must be able to cope with these uncertainties. We need an allowance to cater for such events. Our ultimate goal is that customers will be unaffected when unforeseen events occur.

Q. Could you describe the kinds of unforeseen events that you have encountered in the past?

A. Probably the best way to demonstrate the kind of unforeseen events that occur is to take a

sequence of events that occurred on the Thanksgiving weekend, October the 6th to 8th, 1990.

As is normal on a long weekend, we had excess generation capacity. The demand is depressed on a holiday weekend, so the staff prepared the generation schedule plan on the Friday afternoon which laid out the plan for Saturday, Sunday, Monday, and the following Tuesday, when everyone returned back to work.

As I said, the plan projected a very comfortable situation with an excess capacity all weekend and, in fact, on the Tuesday, when more demand was expected, there was still a comfortable surplus, where we expected a demand of some 16,800 megawatts and had 20,000 megawatts of generation available. As a result, it was not envisaged that we would have to put our most expensive plant on; that is, the Lennox oil-fired generating plant.

Now, the weekend went approximately as predicted. We had a comfortable surplus and we made profitable sales to the Americans. The situation changed on the Monday when, first, the weather forecast changed. It had been a very, very pleasant weekend, but this was now forecast to change, and demand on Tuesday was now forecast to be some 650 megawatts higher.

Again, on Monday, a unit at Lambton was forced out of service because of a boiler tube leak, so we lost a further 500 megawatts. The loss of Lambton wasn't particularly significant on that day, on the Monday, because we had lots of spare, but it would take three days to repair, so it was not going to be available for the Tuesday morning.

...

[12:23 p.m.] The staff at the control centre revised the generation schedule plan and, as a result of this revision, instructed the Lennox generating station to bring on the three units that it had available on the Tuesday morning.

At this point, the situation still looked reasonable. We had sufficient plant to meet the expected demand, but that comfortable surplus I mentioned had now evaporated.

Tuesday morning arrived and as predicted, the weathered had turned nasty. It was cold. It was down to about freezing point. There was drizzle and everyone was back to work and demand was up as expected.

Things worsened very rapidly then. A Nanticoke unit was forced out of service with a transformer oil leak. That was 500 megawatts. The remaining Nanticoke generation was limited because of flue gas conditioning problems, restricting us by a further 200 megawatts.

We had negotiated some purchases from Michigan, but they were restricted by 300 megawatts, because of transmission limitations. All of that tended to worsen the situation. That adds up to 1000 megawatts we had lost.

But things came to a head at ten twenty-two, just as we reached the morning peak, when a Bruce unit was forced out of service with electrical problems. That was an 850-megawatt generating unit. At this point, the position became critical. The staff at the control centre responded immediately. They instructed all hydraulic generation at maximum and all the combustion turbine units to come on as quickly as possible. That was all the generation we had left.

We requested help from our neighbours, but things were tight there as well. We could only get an extra 50 megawatts from New York and nothing from Michigan, because of the transmission limit I just mentioned. We were suddenly in a very, very tight situation, so we alerted our interruptible customers that we may have to interrupt their supplies. In this event, we managed to squeak through. We did not cut them. But it was an extremely close call. So we had gone from feast to famine in three short days.

Q. Would this kind of situation be considered an emergency?

A. No, I wouldn't classify this as an emergency. We have had much worse situations when the interruptible loads did have to be cut or even firm load interrupted. I am sure you will all remember the

tornado that came through Ontario on May 31, 1985. It caused extensive damage across the province, more particularly for Ontario Hydro; it downed several of our transmission lines. Very suddenly, we lost over 3,000 megawatts of generation and over 700 megawatts of customer load.

Now the operators' priorities when this kind of event occurs, an emergency, is to stabilize the situation. They wish to contain it such that it does not spread to other parts of the province or indeed other parts of interconnected utilities.

When they have stabilized the situation, their priorities are then to restore supplies to customers as quickly as possible. On this particular instance, we were able to restore all our firm customers within half an hour and the interruptible loads within four hours.

We were able to restore so quickly because we had significant amount of spare capacity connected to the system when the event occurred, which one could say to some extent there was some luck involved in that we had more than our minimum. But that was essentially why we were able to restore so quickly, and, of course, the prompt actions of the operators at the control centre.

Both those examples show how changes can happen on the power system. The first one happened slowly over several days and we were able to change our plans to accommodate these changes. And the customers were largely unaware of what had gone on.

In the second instance, because it happened so suddenly and it was so dramatic, the load loss was inevitable, but, fortunately, such an event is rare. But I think both show the vital role that spare capacity has to play in system operation. It provides us with the flexibility to respond to unforeseen events, and hence prevents, or at least minimizes, the impacts on our customers.

Q. Can the power system operators do anything to ensure that they have this kind of flexibility?

A. The operators, when planning the generation schedule plan, can provide this flexibility by scheduling on extra generators over and above those needed to simply meet the demand. We call this extra operating reserve. Typically, it would be part-loaded machines, so a 500-megawatt machine delivering 450 megawatts provides us with 50 megawatts of operating reserve. Or combustion turbine units which can be brought on load quickly, they provide operating reserve

as well.

Q. How much operating reserve do you keep on hand?

A. We classify operating reserve by how quickly it can respond when needed. So we have two levels defined: ten-minute reserve and thirty-minute reserve. Ten-minute reserve is designed to cater for a sudden loss, the type of loss that I just described, as when the tornado went through.

We define sudden losses such as that as a contingency, and so how much ten-minute reserve one keeps is dependent upon what is the biggest single contingency we wish to protect against. We obviously want to protect against as much as possible, but that has to be tempered against the cost of providing it.

We keep sufficient ten-minute reserve to cope with the single biggest generation loss on the system at any given point in time. So if, for instance, a Darlington generating unit generating 900 megawatts is the single biggest generator, then we will maintain 900 megawatts of ten-minute reserve.

Now following a contingency, the bulk electricity system is vulnerable to a second contingency occurring, and that is the intent of thirty-minute reserve. Again, this is a trade-off

between costs and ensuring reliability. We maintain half the second contingency.

So, if again the second biggest contingency was, say, a Bruce unit of 850 megawatts, we would maintain 425 megawatts of thirty-minute reserve. We define our operating reserve as the sum of our ten- and thirty-minute reserve, so in those examples I have just quoted, that would be some 1300 megawatts, 900 and 400. But this does vary depending on system conditions.

I should mention it isn't always a generation loss, the loss of a single generating unit, which is the single biggest contingency. Sometimes the transmission network is configured such that if we lose a certain transmission circuit, it will cause more than one unit to be removed from the interconnect system, in which case that would become the single biggest contingency.

So the effect on the schedule - to bring it back to where we started - the extra generation scheduled on for reserve means that we have more generation on than simply to meet the demand.

So I would like to sum up the four factors and how they influence the schedule. Returning to Exhibit 136, page 24, that was the basic schedule

that I started off discussing. So minimizing costs, that was the first objective that determines the basic ordering schedule of the plan, and optimizing the use for peak shaving, that kind of consideration.

Respecting internal system constraints, the generation inflexibility must be factored in. As I mentioned, the ability of the generating units to ramp up quickly in the mornings to meet the sudden increase in load or the minimum shut-down times, that kind of thing. The transmission limits I mentioned, they may mean that not all of the generation is usable, as I indicated in the example with Bruce.

Respecting the environmental considerations, as you recall, the acid gas caused deratings of plant, which means you have to put more generating units on to meet the load. It changed the order in which we scheduled plant and it changed our purchase and sales strategy.

The hydraulic environmental considerations meant that it was not always possible to achieve optimum peak shaving while at the same time respecting the environmental concerns.

And fourth and lastly, the reliability means that extra plant is scheduled on over and above that needed to simply meet the demand.

Now as you can see, they are four very different factors and, in fact, they are factors which are often in conflict with one another. So, the essence of system operation is to strike a balance between these different objectives.

Q. Can we go back to contingencies? If Hydro suddenly lost its biggest generating unit, could it make up for that lost generation immediately from the operating reserve?

A. No, it cannot. When a sudden generation loss occurs, there is an instanenous need to replace the lost power. Because we are interconnected with other utilities, that need is filled by a combination of our own generation responding and those of our neighbours responding.

When our neighbours' generation responds, then it shows up as an increase in the tie-line flows, the amount of megawatts we have coming into us from our neighbouring utilities.

In fact, with an interconnection such as we have, more than 90 per cent of the loss would be made up from the tie lines. What ten-minute reserve allows us to do is to return the tie-line flows to normal quickly, that is, within ten minutes.

Q. Could you tell us whether there are

any other operating implications of being interconnected?

A. As Mr. Snelson mentioned, we are part of the the eastern interconnection which stretches from Canada to Florida, and from the Atlantic to the Rocky Mountains. Because we are interconnected, we enjoy four principal benefits:

First, all utilities provide mutual support in the event of contingencies occurring, such as what I have just described, so we all enjoy a more reliable supply of power.

Second, because this mutual support is available, each utility carries less reserve, hence we all save money.

Third, it provides a market for sales and purchases. Again, mutual benefit. We can all save money.

And fourthly, that huge interconnection and the amount of generating plant connected at any one time can be as much as 400,000 megawatts, provides an extremely stable base and we have a very steady frequency here in Ontario and throughout the interconnection.

However, because interconnected systems react with one another, it is essential that all

utilities design and operate their system to certain mutually-agreed standards. Otherwise, a delinquent utility would become a burden on the other. In extreme circumstances, a delinquent utility could cause system collapse.

These standards that I referred to were developed by the North American Electric Reliability Council, referred to as NAERC, which covers all of the United States and Canada. More specifically for Ontario Hydro, we are members of the Northeast Power Co-ordinating Council, NPCC, which is one of the groups that form NAERC.

It covers the northeast portion of the continent. These councils develop the standards and they monitor adherence to the standards; for example, the levels of operating reserve I described earlier, they are set by NPCC, so all utilities will have that amount of operating reserve.

All of these standards are designed to ensure the integrity of the interconnected power system; and as a member, Ontario Hydro must comply with these standards.

Q. Earlier, you mentioned purchases and sales. Could you describe how you go about making these transactions?

A. We make transactions with the interconnected utilities under the general principles laid out in interconnection agreements, where basic pricing structures are negotiated and transactions are carried out within that structure.

There are many, many different types of transactions, and we couldn't possibly list them all, but they do fall under one of three broad categories.

The first category is firm, firm purchases, and sales. These are when one utility makes a long-term commitment - by long term I mean several years - to supply power to another utility. Presently, Ontario Hydro has one firm sale. 112 megawatts to Vermont which expires in 1992. There are no plans to extend this and there no plans for any other firm sales. In fact, our recent National Energy Board application had no application for firm sales as part of it.

Turning to firm purchases, the Manitoba purchase would be a firm purchase in that it would be guaranteed over a number of years. The second type is a capacity-type purchase or sale, where one utility identifies a deficiency in the short term, perhaps days weeks or months ahead.

In this instance, a purchaser pays a

capacity charge, so many dollars per megawatt, which could be regarded as a reservation charge to make sure this power is available. He has identified he needs it, so he wants to be sure that he is going to get it.

...

[12:40 p.m.] When the power is taken a further charge, an energy charge is made of so many dollars per megawatthour when the power is actually taken.

The thing about a capacity-type purchase is that once it's established, the seller will do all in its power to continue the sale even though they may become short of power themselves, they will go to great lengths to ensure that that capacity-type purchase carries on.

The third type is an economy type transaction. This is where neither side needs the power, simply that one has cheaper generation available which can displace the power in another utility. Typically, this type of transaction takes place such that both sides benefit equally from the transaction.

Typically, if one utility has generation available at $20 per megawatthour, and another utility has generation that it was going to run that was $30 a megawatthour, then a transaction would be struck at, say, $25 a megawatthour, so that both would make $5 a megawatthour on the transaction.

The thing to be remembered about economy sales is that they can be withdrawn immediately by either side. So they cannot be relied upon over the long haul. They are simply taking place for pure

economic reasons.

Q. Finally, Mr. Barrie, with respect to the operating reserve level that you described earlier on, does Hydro always have sufficient available generating capacity?

A. Not always. As we enter the operating time frame we can experience periods of fat; that is, where we have lots of available capacity and lots of reserve; and we can have lean periods when we have very little. We tend to have fat periods if there has been low load growth over a number years, for instance, in the 1981/82 recession. When we have such fat periods, we pursue exports and we consider mothballing a plant.

Conversely, we have lean periods when we have high load growth. From 1983 through 1989, we experienced very high load growth. Or, if new generation is delayed or if we have poor performance from existing plant. All of this will tend to make it a very lean situation, and, in such cases, we will seek purchases and we will consider demothballing a plant.

In lean times, the system is under more stress as we struggle to cope with inadequate generation. This stress can be manifested in a number of ways. For example, we will tend to seek more

occasions when we have to do voltage reductions, more customers appeals, more times where we have to interrupt our interruptible customers, more capacity type purchases. These would be the kinds of things that one experiences when the system is going through a lean period. If it's severe enough, we would even have firm load cuts, but fortunately, we haven't experienced that in Ontario recently.

To demonstrate what I mean, I picked one of those indices which indicate the kind of stress, that is the interruptible loads. This is page 26 in the exhibit. The data on here, by the way, was provided in response to two interrogatories, 2.14.32 and 2.14.33, the only addition is that I put the 1990 data in as well.

If I could just explain what is on that chart? It shows the number of interruptible load cuts each year, so the total number shows the total cuts.

The hatch-marked portion shows those that are generation-related. So it's really the hatch-marked portion which I would like to draw your attention to.

So typically, take the highest one, in 1989 there were a total of 24 of which 22 were generation-related.

So, in the early 1990s, as you see, there was zero use of interruptible loads. We had service generation and it was at that time that we mothballed Hearn, Keith, Lennox and Thunder Bay Unit 1. In '83 throughout '89, we experienced the high load growth, we experienced delays in in-service generating plant, we experienced transmission limitations and environmental restrictions. That resulted in a steady increase in the use of the interruptible loads.

It peaked in 1989. The effect of the downturn in demand in 1990 is evident here, as the stress on the system was considerably relieved.

I want to stress before I leave this, though, that the use of CILs, or, indeed, any of those other indicators, are simply indicators of stress. You cannot read it off here and say there was a one-to-one relationship; it is merely an indicator.

Q. Thank you, Mr. Barrie.

Mr. Taborek, I will come back to you now.

Mr. Barrie has addressed the need for a reserve margin in the operating time frame to allow for unforeseen changes in load or generation. I gather that the same is true in planning time frame?

MR. TABOREK: A. Yes. But before I answer the question, I would just like to correct

something. I misspoke myself earlier. My colleagues reminded me that when I was comparing our 32,500 megawatts of generation with the population, I said, apparently, 3,000 megawatts per thousand population. It should be 3 megawatts per thousand population.

Q. Thank you.

A. And with that, yes, Mr. Barrie has described to you how the changes in load and generation day-to-day can change the balance on the system, and a margin is noted for these kinds of uncertainties in the long term as well. It's to be reasonably sure that there will be a reliable supply of electricity because the demand and the supply situation is unlikely to be as it's forecast.

Q. Chapter 4 of the Demand/Supply Plan talks about a reserve margin of 24 per cent. What do you mean by that?

A. That means that for every megawatt of customer load there must be 1.24 megawatts on average of capacity available to be reasonably sure of meeting the load reliably.

Q. Let me give an example, which is on page 27 of Exhibit 136, which shows that if we consider our 32,000 -- if we expected a demand of about 26,000 megawatts, 26,300, and we had typically 32,500

megawatts of capacity, we would have a reserve expressed in megawatts of about 6,200 megawatts.

Expressing that in per cent terms, the reserve margin would be 6,200 divided by the load, 26,300 in percentage terms, 24 per cent.

Of course, the greater this reserve margin, the greater the reliability.

Q. I would like to begin by explaining the analytical approach that's taken to calculating generation reliability or reserve margin.

A. There are three terms that are widely used in analyzing and discussing generation reliability. These terms are illustrated on page 28 of Exhibit 136. I have mentioned to you reserve margin and the other two terms that we will be discussing are unsupplied system minutes and total customer costs and we will discuss the relationship between these.

When we look at the demand that has to be met on the system and the capacity that has to be provided, we note the megawatts of the demand, the megawatts of capacity and we may add demand management measures to reduce demand or supply measures to increase the capacity. The reserve margin can be readily calculated then, using the simple formula on the previous page.

That is illustrated on page 28 by adjusting demand and supply on the system and computing the reserve margin.

What we then do is we use mathematical models to compute a parameter we use called "unsupplied energy." The model we use to do this is called our frequency-and-duration model. And what it is is a model that basically describes all the things that can -- as many, a number of the things that can go wrong. Your system, by contrast -- production models that we will come to later describes what you'll most likely do, this describes the unlikely contingencies that come about.

We compute, then, the probabilities of not being able to supply customer load for reasons of demand being higher than we expected, or generation not being available when we expected it.

And the term "unsupplied system minutes," you get out a term megawatthours for energy, but to scale it to the size of your system, we divide it by the peak load to get system minutes.

Now, having done that, we then go on and we compute two parameters, and, again, they are illustrated on page 28. One is having added demand and supply measures to the system, we can determine the

cost of these additions and the cost of operating the system, and so we can compute the cost of supply.

With that particular supply - and we have determined how much unsupplied energy there is - by surveys, we determine how much customers are willing to pay for that unsupplied energy, and so we can take the system minutes, multiply it by the customer interruption costs and determine the customer interruption cost.

The sum of these is the total customer cost. The customer pays the supply cost through his rates and he pays the customer damage costs through his own inconvenience, or measures that he takes to cover the fact that interruptions can occur.

What we do with this is we seek for some value, some amount of backup to the customer that gives the minimum total customer cost.

So, if we go to page 30 of Exhibit 136 --

Q. I think you mean page 29.

A. Sorry, page 29, yes, of 136.

The typical calculation I have described to you is, in effect, one point on this axis. So, we will determine a certain mix of capacity and load, we will work out a reserve margin, we will work out a system minutes of unsupplied energy, that will give us

a particular cost of supply, a particular value of unsupplied energy, customer damage cost and a particular total, and then we will basically vary the demand and the supply to define this particular curve. And the minimum on the curve is the minimum total customer cost.

What you find, of course, is that the more backup you have, the higher the supply cost, but the lower the customer damage cost and vice versa.

And you will note, as was made earlier, we don't attempt to provide a perfect system. What we attempt to provide is a system that gives minimum total customer cost.

Having stated this point, I will return to page 28, and having given three numbers or three parameters that will be used frequently from this point on, the relationship between them is that if you would like to know how much reliability you should provide, one looks at something like total customer cost, one looks to be somewhere near the minimum.

If you want to know how much reliability did I end up with, you look at unsupplied system minutes. And if you want to compare one system with another, you would compare their system minutes of unsupplied energy.

If you want to add generation or demand management measures to a plan in computing long-term plans, what one looks at is reserve margin. It's an easier parameter to use in adjusting plans than these others which require you to go through successive loops of calculation.

...

[12:55 p.m.] Q. And do all utilities use this analytical approach, which you have just described?

A. No. I will come back to page 28 again.

Most utilities do not use the concept of minimum total customer cost. They are uncomfortable with defining what customer cost is and translating unsupplied energy to customer cost.

Many U.S. utilities do a computation where they produce something called LOLP, Loss of Load Probability, so the U.S. utilities, in effect, do not do this part of the calculation; they do LOLP instead of unsupplied system minutes.

Now, what a LOLP is, is the probability of losing load in a peak hour and you will typically see numbers of the order of 1 in 2,400, which to give you another feel for it, it is often described one day in 10 years, although it doesn't happen that way. It is just a measure of the probability.

Now, because they do not use total customer cost to say, 'How much should I have,' what they do is, they substitute a collective judgment for how much LOLP they should have. And these collective judgments are made in reliability councils that utilities form, both regionally and across North

America. And a LOLP of 1 in 2,400 or one day in 10 years is quite a common one that is used in the United States.

Now, other utilities, basically, do not go through the calculation, at all. What they do simply is they have learned over time that a certain reserve margin is suitable for their system and they basically work to a research margin of 18, 20, 22, 24 per cent. And as a matter of fact, there is a story, I guess, that the LOLP of one day in 10 years is the result of utilities sort of working their calculations until they got a reserve margin they liked and said, 'Good. We will use that.'

By and large, Hydro's approach, as you can see, places more emphasis on analysis than, I think, most other utilities do before we begin to apply judgments as to how much reserve we should have.

Q. Could you explain why there is so much emphasis on judgment in this area?

A. It is a critical aspect of reliability planning. Earlier, I mentioned that these reliability models attempt to predict what can go wrong with the system or some of the things that can go wrong, and you cannot predict all of them, and because they are rare events on a complex system, it is very

difficult to get good data on even those that do occur.

What you end up doing is making varied calculations involving very small differences in these very trying circumstances, and so there are limits to what analysis will do for you. To the extent I mentioned, many utilities use much less of it than we do. And so basically having done calculations here, this is especially an area where a good deal of judgment is required before making the actual choice of the margin.

Q. What are some of the areas where judgment enters into generation reliability planning?

A. We make judgments about where we should be with respect to the minimum total customer cost; i.e., where is the right place to be on the curve.

We also make judgments about how well our theory and our analysis fits with our experience, and we also make judgments or review the judgments of other utilities before we choose our reserve margin.

Q. If I might just ask you what you mean when you say that you want to make judgments about the right place on the curve.

A. I will just return to page 29 to illustrate this. This shows the curve of total

customer cost and what you will see is that the minimum occurs over a fairly broad range. It is not a very sharp clearly defined minimum and you can begin to make some judgments about whether you might perhaps be moving to the more reliable side of the minimum because you can gain substantially in reliability for a very small increase in cost, as you can see.

Now, another set of judgments you can make is that you may find at some particular time that the cost of providing the supply are much more than you had anticipated, and you can look again and you can note that, again, to the less reliable point from the minimum, that it is some -- you have some flexibility before customer damage costs start tending rise sharply. And so, for brief periods of time, you can assume a slightly higher risk if the cost of providing the resources is perhaps higher than you anticipate or you judge to be too high.

MRS. FORMUSA: This might be an appropriate time for the lunch break.

THE CHAIRMAN: Stop until two-thirty.

THE REGISTRAR: The hearing will adjourn until two-thirty.

---Luncheon recess at 1:02 p.m.

...

--On resuming at 2:32 p.m.

THE REGISTRAR: Please come to order. This hearing is now in session. Please be seated.

MRS. FORMUSA: Q. Mr. Taborek, I would like to turn now to the difference between the operating and the planning reserving margins. Mr. Barrie made mention of an operating reserve margin and you have introduced the concept of a planning reserve margin. Are the reserve margins that Mr. Barrie has referred to the same as those that you are talking about?

MR. TABOREK: A. The principle is the same, but the practice is different. The principle is the same, in that we require a margin to deal with the uncertainties we face in forecasts of load or generation. We have certain measures that we can apply to meet those. One of those measures is to have a margin.

Now, the practice is different in three ways, at least. One is the way in which the margin is determined. The other is the degree of uncertainty that has to be dealt with. And then the final and third is the measures that are available in the operating and the planning time frame for dealing with the margin with the uncertainty.

Q. I would like you to deal with each each of those differences in turn. Firstly, how do you determine the amount of reliability or margin to be provided in each time frame?

operating reserve margin

A. Now, Mr. Barrie in his description laid out for you a deterministic criteria. It is based on a specific contingency. He would cover the loss of the single biggest generator, perhaps a single transmission fault, and then half of the succeeding fault, so it is tied to a specific number.

In our case, what we do is we describe the probability of loads being more or less, of generation being more or less than forecast, and do a probability assessment of having enough energy to meet people's demands or not. So theirs is deterministic and ours is probabilistic.

planning reserve M

Q. The second difference that you mentioned between the two types of margins was uncertainty. Could you explain why the degree of uncertainty is different?

A. Basically, it is because we look further ahead, and the further you look into the future, the greater the uncertainty.

Q. And finally, with respect to the third distinction, what are the different remedial

measures that are available in the planning and operating time frames?

A. Now, both time frames, there are a number of measures available in each. It is the ultimate measure which is the special difference.

In the planning time frame, the question is whether or not to bring on-line generation that already exists. In the planning time frame, the question we are looking at is whether to construct new generation or to implement new demand measures.

Q. I would like to turn now to the future capability of the existing system. How did you go about forecasting the future reserve requirements of the existing system?

A. I described for you a procedure by which we analyze the reliability of the generating system. Hydro had earlier conducted an analysis like that and chose the parameter of system minutes as its yardstick for measuring reliability and chose as a value for that parameter 25 system minutes.

In the initial stages of the Demand/Supply Plan, what we did was take that parameter of 25 system minutes and compute the reserve margins that gave that amount of system minutes of unsupplied energy.

The system minutes translated into reserve margins roughly from 21 to 24 per cent - excuse me, 22 to 24 per cent - of something we call the planning firm load. We used the range of 22 to 24 per cent reserve margin in developing the demand/supply plans.

Now, I earlier also indicated to you that there could be circumstances, since we are working along the flat bottom of a customer cost curve, which may go a little more, you may go a little less.

Frequently, when we are looking at additions to the existing system, we found that under conditions of very high load growth that we would have to add a good many peaking units quickly to the system. And we felt this would give the system an inappropriate balance - too much peaking, not enough base - and there were some questions, really, as to whether you could build that fast.

As a result, in the circumstances, we made a judgment that, for brief periods of time in the upper load growth, we would allow our reserve margins to slip to as low as 20 per cent.

I would just note that what I have done is, I have shifted from talking about system minutes, which is a measure of reliability, to talking about

reserve margin. And the reason I have done that is that to continue calculating from system minutes to reserve margin every time you have to do this, gets you into long, tedious calculations, so it is a lot more direct and to the point just to work with a range of reserve margins.

Q. So, when you were working on the demand/supply plan cases, were they then developed using a range of reserve margins?

A. Yes. We took the 25 system minutes and from that, we determined that a range of reserve margins from 20 to 24 per cent was appropriate for use in the demand/supply plans, and that was based on being in the range of minimum total customer costs.

Q. If you are doing that, it would appear that you might want to try and keep reliability and system minutes constant within a case, and from case to case. Is that not so?

A. Yes, that is right. It would be a puristic thing to do to keep 25 system minutes constant through all the cases.

Theoretically, the reserve margin should change a bit. As the system gets larger, the reserve margin for a constant reliability and system minutes should decline, and similarly, depending on what you

add to the system, if you add an unreliable generator or demand measure, of course, you would have to put up your margin.

If you add a more reliable generator demand measure, you would be able to drop your margin, so that you might have your reserve margin changing with the system.

Now, there are several reasons why we do that, but first of all, we are looking essentially at the existing system and the first increments that are being added to it, and therefore, those small increments being added into this large system do not significantly vary the reserve margin. It varies over a long period of time.

And similarly, the size of the system changes fairly slowly over a long period of time. On a practical measure, the kinds of calculations that would require you working from a constant system minutes all the way through is very lengthy and very tedious and adds very little to the final result.

I think that is especially true because practically, operationally, and in a planning sense, you do not really plan or operate to a fixed reserve margin. You do let it vary from point to point.

Now, you have to be careful, though, in

that the plans you develop won't all be of equal reliability all through the planning period. So, when you begin to compare plans, what you have to do is make adjustments for having taken this more efficient course. And you will have adders that you should put in, to make up for the reliability differences between one plan and another, when you are working with reserve margins.

Q. In taking this approach, how do you take into account the effects of smaller, more reliable generation being added to the system?

A. Well, we do it in two ways. One of the ways is, we have to ask if we are correctly reflecting the impact of this smaller, more reliable generation on the existing system.

And then, the other point we have to address is whether we are crediting this new generation with the reliability benefits it is giving us.

...

[2:42 p.m.] So, first of all, when we add new generation on our system, and we adjust the mix of demand/supply measures, determine reserve margin, go through our reliability model, our reliability model does recognize the particular characteristics of each of the resources that's added. And so, as we add more reliable generation, the reserve margin that we require will gradually decline, so it is recognized.

Now, what isn't obvious from that is that -- in that that gets rolled up into the system number, the system reserve margin declining, what isn't obvious from that is how does the person, let's say it's an NUG, especially, who is providing that generation, gets recognition for his reliability, which for the unit may be much better for the system as a whole. And that part of the recognition is given through the avoided cost calculation and that will be dealt with in the next panel.

Q. To conclude this section, then, what is the significance of the existing system's reserve margin for the Demand/Supply Plan?

A. The timing and the amount of new resources adding to the existing system is determined by the reserve margin of the existing system. So, if we had used something more than 24 per cent, resources

would have been required sooner; if we had used something less, it would have been required later.

And then, similarly, the higher the system reserve margin is, the higher our avoided costs would be. The lower as well. So, those are two key elements where the reserve margin of the existing system has an impact on the plans that will be unfolding later.

Q. In view of the importance of the reserve margin for the existing system on the plan, I understand that you undertook a review of your reliability criteria, which is documented in Exhibit 87?

A. Yes. We were quite concerned to ensure that the analysis we had done and the judgments we made would stand the test, because of the importance of the material. And so we did a review, which is documented in Exhibit 87, for just that purpose.

We asked ourselves the question, basically, how do we know that we have the right reserve margins? And we developed three tests, if you will. One, we thought we would compare ourselves with other utilities, with the numbers they had. This was especially true because we are aware that utilities use wide ranges of reserve margins, and we wanted to know

why we were different or if we were the same; if we were still correct.

The second thing we did was we compared ourselves -- or we looked back at our own recent operating experience to ask ourselves how close we had got to problems. Mr. Barrie described one typical example. And if we had been more or less than the reserve margin we had at the time, could we have tolerated it or would it have led to even more problems?

Then, finally, we re-did our analysis; the approach, I suggested to you, of determining where the minimum total customer cost occurred, using the most up-to-date data and an updated model.

Q. What did your review indicate to you about the reserve margins?

A. Now, the review showed that the 20 to 24 per cent reserve margin range used in the D/SP was about right for the Hydro system. And when we are looking at the minimum total customer cost curve, I think it tends to bracket the minimum point on the curve, and that I would judge 24 per cent as being a bit to the more reliable side of the minimum total customer cost which you would get analytically, but that it's in the range where there is not a

significantly higher cost.

And I would judge 20 per cent as being to the lower reliability side of the minimum total customer cost, and that it's an acceptable risk to be there temporarily, when other circumstances make it difficult or perhaps inappropriate to provide higher margins.

Q. And with respect to system minutes, what did the review indicate about the system minutes?

A. While we ended up with roughly the same reserve margin range, instead of having our minimum total customer -- excuse me, instead of using an unsupplied energy of 25 system minutes, we determined that an unsupplied energy of 10 system minutes gave the minimum total customer cost.

It took us some time to determine just why this was the case. And we now believe that we understand why the reserve margin is the same but the system minutes are lower. And the reason for that is that, in the calculations that were done in the early '80s, when the 25-system-minute criteria was determined, there was a judgment made that up to 10 per cent of the load could be deferred through public appeals at no significant cost.

And the number of 10 per cent, we feel,

is quite large. And we have, over the years, done tests - well, I guess they are not tests, we have made public appeals, and no tests about it - and we now believe that something like 2 per cent is a more appropriate amount for a limited or no-cost public appeal. And it's that factor which primarily accounts for the number of system minutes going from 25 to 10.

The reason that the reserve margin didn't change while the system minutes changed is that in the early '80s, the forced outage rates of units on the system was quite high. And a little later we will be looking at some of these and you will see that there would be very high forced outage rates. They tended to drop as we got into the '80s, and, consequently we are now planning with lower forced outage rates than at the time. That means, simply, the generators don't go out of service unexpectedly as much now as they had earlier. And it's those two factors that account for the new balance.

One other thing I would mention. The 25 system minutes determined earlier was not purported to be the minimum total customer costs, the exact minimum on the curve, but was felt to be to the more reliable side at a small cost increment, so that is another factor that enters into the rationalization.

Q. You said that when you were doing your review, you compared Ontario Hydro with other utilities. What were the results of that comparison?

A. We sent survey forms to quite a number, and we received responses from 29. We got a very good response. We promised to give them the information and they all periodically do the same thing we do. And this is a description--

Q. It's page 30, of Exhibit 136?

A. --which is page 30 of Exhibit 136, of the reserve margins they reported to us.

You will see utilities here, three hydraulic utilities, B.C. Hydro, Hydro-Quebec, and Manitoba Hydro, largely hydraulic.

Going down through a number of U.S. utilities who are more thermally than hydro-based, so, Consumers Power and Detroit, both in Michigan. You see Illinois. You will see some areas where New York is mentioned. This is describing a power pool that we would approach.

Some U.S. utilities, or many U.S. utilities, plan on a pool basis. A number of small utilities will join with the pool to get the benefits of large systems and diversity of loads and interconnections.

We also have some foreign utilities, Tokyo Electric, Italy, and a number of other European utilities.

We have divided the hydraulic and the thermal utilities into two groups because what jumps out immediately is that the hydraulic utilities have a much lower reserve margin than the thermal utilities do. And, basically, this is because of the characteristics of their generating units.

I mentioned earlier our own hydraulic generators tend to be small, they tend to be well proven, and I will mention to you later, they tend to have very low forced outage rates, being a proven technology. So you would expect any hydraulic utility to have a low reserve margin. So, it explains why those particular utilities are less than us.

Now, when we looked at these other utilities, we determined that the mean of the thermal utilities was about 20 per cent, compared to the 20 to 24 per cent range we were looking at.

Now, I have mentioned that the reserve margin you have really depends on the kinds of resources you are using to meet the load, it depends on the criteria you use. Not everybody will have the same margin; it depends your system. We paid particular

attention to those who had reserve margins of less than Hydro. We were testing a hypothesis that we were too high, why couldn't we go lower?

We by no means were able to do a rigorous rationalization, but what we were able to do is narrow the band, if you will, in our own mind. And we found that a number of utilities who had low reserve margins were small utilities in an interconnected system, and they could take advantage of the interconnection, in large relative measure, so that they did not have to carry that reserve margin on their own; they could get get it from the pool.

Some of these utilities, being small systems and poorly connected, had to work to lower reliability levels. I mentioned the amount of emergency measures you assume. If you assume 10 per cent in public appeals, as compared to 2 per cent, you will get changes. Utilities make different allowances for emergency measures.

I mentioned earlier when I was talking about load shapes, if you have a peaky load shape, you get close, you have a problem, it can be a problem for two hours. So, if you have a flat load shape, you have a problem and you have it for 16 hours. And so we feel that one of the explanators, if you will, is the fact

that some have peaky curves and can drop their margin a bit because the consequences of being long are not so bad.

By and large, we felt that these utilities with reserve margins less than us, there were reasons that they could legitimately be less based on their system, and this is written up in detail in Exhibit 87.

Now, we also felt that it wasn't quite appropriate to compare us, one for one, with small utilities and with hydraulic utilities. And, therefore, we felt the singlemost direct comparison that we could make would be to pick utilities who were as much like us in their characteristics as possible. And so these would be large. They would be primarily thermal.

...

[3:00 p.m.] So, we developed a smaller set from the sample. And so, here, now, what you see is again for these --

Q. That's page 31?

A. Page 31 of Exhibit 136. The smaller set of larger utilities or pools. So a German utility, ourselves, and you will note here also we have picked pools. The abreviations, ECAR, MAPP, MAIN, et cetera, are American reliability pools. I have just put beside themselves the proximate geographic area in which they are located.

And you will note that the mean in this case is slightly larger than the mean of the smaller individual utilities at about 21 per cent, and that the main outlyer in this case is Maine, in the Illinois area, and we note they have a rather peaky load shape.

So, this comparison of the others at 21 per cent, and us in the range of 20 to 24 per cent, is the outcome of our review of other utilities.

Q. Turning now to the second part of the review that you conducted, what did the review of your recent reliability experience indicate?

A. That review indicated a reserve margin of about 22 per cent was appropriate.

Q. And how did you reach that

conclusion?

A. I will show you a map to take you through a calculation that we did and I would like to describe to you.

Q. That's page....?

A. Page 32 of Exhibit 136.

We work with a lead time, because if anything is going to happen four years and beyond -- or beyond four years, pardon me, we can build new generation to meet it. So that the lead time, the time it takes us to recognize the problem, to get new resources in place is a critical factor in setting reserve margins.

So here we have assumed that it would take us four years to get a combustion turbine unit or numbers of combustion turbine units in service. So that deals with the period beyond four years.

Now, in the period up to four years, what we have to do is rely on two things. One is the reserve margin and the other are the emergency measures that we will have at our disposal in that time. And so, what I have shown on this map is within a 4-year period - which is how long it takes us to get new generation in place - we are going to look first of all at how much uncertainty we have experienced within that

time frame. And for convenience, I am going to break that into two parts, the four years up to the operating year and then, the operating year. And then, that will determine, that's the total uncertainty.

Then, I am going to look at the measures we have available to meet that uncertainty, and those measures are, basically, the emergency measures and the reserve margin. So I am going to do this, plus this, minus that equals that.

Q. Let's start with the first box, then, on the chart on page 32. I would like to ask you what kind of uncertainties you had to deal in the four years from when the forecast was made to the operating year?

A. Looking at page 33 of Exhibit 136, we show how much uncertainty, how much error, we make in forecasting. And in this particular case, with a 4-year horizon, we looked, for instance, at plans we did in 1981 for 1985, and then in '82 for '86, et cetera, and in '85 for '89. We, then, looked at how much of an error we made in loads, how much of an error we made in forecasting the generation that we would have available and then the sum of the two, taking the two together to give the total error, both in megawatts and in per cent terms.

So, for example, in 1981, we

underforecast the load in 1985 by 700 megawatts. You will note that through the years we underforecast the load by as little at 400 or as much as 2100 megawatts. Now, this was a period of economic recovery, coming out of a recession in the early part of this period.

Turning now to the generation we expected to have in place, in 1981, we overforecast the generation that we would have in place, we expected to have in place - in 1985 - by 1500 megawatts. And through that period, we always underforecast -- excuse me, we always overforecast the amount of generation that we would have, by anywhere from 500 megawatts to 1800 megawatts. We are persistent.

Our total error, then, is the amount by which we underforecast load and overforecast generation. So, our total errors in the period were from as little as 900 megawatts to as much as 3900 megawatts. Now, if we just convert this to percentage terms, you can see that we made errors from 4 to 15 per cent in this period.

I might just mention, the reason that the generation was not there as we had forecast, there were two major reasons for this occurring: One was delays in the in-service of new units, and the other was units taken out for retubing, by and large.

So, what we note from this, and a point that I will take on later, is that this is a probabilistic event. I have shown you a number of cases in which our forecast has hurt reliability, and you have to say that, if you did this overall history, you would have cases where we underforecast, we did the opposite. But what we have shown you is this brief review, this sample of five years, we did hit a 15 per cent error. It's a credible error.

Q. If we can deal with the second box on the chart on page 32, and that is the one-year operating period. What kind of uncertainty was experienced in the actual operating year?

A. Turning to page 34 of Exhibit 136, we are now looking at the actual operations in each year. And we went through the year hour-by-hour and determined the capacity we had on hand, the load that we had, and the reserve that we had; and from that, we did some adjustments. We noted there were times when we had units out, we had units out, planned out for maintenance in the peak period. Utilities will occasionally do this when they are a little flush, so we corrected for that, because you would not do that in a proper reliability test.

And so correcting for planned outages, we

found that we went into the year with reserve margins ranging from 14 to 23 per cent, and for convenience in calculating, we assumed an average of 17 per cent.

Now, I will just take a brief diversion here, because having entered the year with a 17 per cent reserve margin, we were able then to count the number of times that we had to use emergency measures by just counting the hours in which they would have been required, or, to be a little more precise, the number of times in which the load exceeded our capacity, they could have called up emergency measures.

And we found that with the 17 per cent margin on average, we were experiencing loads in excess of our capacity of about 150 hours a year for about 2 per cent of the year, 8,760 hours in a year.

We then asked ourselves, suppose we had had a lower reserve margin. So we subtracted 1,000 megawatts from the reserve margin, roughly 4 per cent and checked again with 13 per cent reserve margin, and then we found that the number of times the load exceeded capacity jumped to about 720 hours, roughly 8 per cent of the year.

And finally, taking another slice of 4 per cent, 1,000 megawatts off the reserve margin, gave us 1900 hours a year or 22 per cent of the time when

the loads were exceeding our capacity.

From this latter part, we concluded that we really didn't want to lower our reserve margin in the year anymore than we had done. We were on the boundary. And consequently, what we said was that this this number, 17 per cent, the average for those years, correcting for the fact that we had done some planned outage, was a reasonable number to use for uncertainty in the year.

Q. In summary then, what did this tell you about the total amount of uncertainty that you might face in the future in those two time periods?

A. Now, we will look at page 35 and simply note, we pull together now -- define the total uncertainty, the two numbers that had I indicated earlier. In the forecast period, we had an error of 15 per cent; in the operating period, something like 17 per cent, so it looks like with this kind of a time horizon you should be planning to deal with uncertainties of about 32 per cent. This is the range of uncertainty you have to face with that time period.

Q. With those kinds of uncertainties that you would have had to deal with in the past, did you, in fact, experience any serious system problems?

A. We had normal problems, I think, is

the best way to describe it.

During this period, from 1985 to 1989, we and much of North America were coming out of a period - the 70s - in which there had been an overforecasting of demand, a surplus of generation. We had a good margin ourselves, I mentioned we actually had some units planned out on the peak. The rest of North America, much of the rest of North America, was in a similar situation.

We also had mothballed generation. We had the 2000 megawatts oil-fired Lennox plant in mothballs, and so our first response was to bring those 2000 megawatts at Lennox back into service, and so that plant is now in service. However, I would note that we don't expect to have mothballed generation available in future.

Lennox is back in. The only generation not now in service are Hearn and Keith, and we don't believe that they will provide a meaningful long-term mothballed reserve.

...

[3:12 p.m.] Q. So, what do you expect that you would do in the future without that kind of mothballed back-up?

A. Without mothballed generation, we will either have to use, as I mentioned earlier on my road map, use emergency measures or the reserve margin.

Q. On that road map on page 32, then, the third box is Emergency Measures, and perhaps you could explain what you mean by "emergency measures."

A. Yes. Page 36 of Exhibit 136 lists the emergency measures. They are interruptible loads, interconnections, voltage reductions, and public appeals.

Mr. Barrie mentioned earlier that certain large customers get discounts in their rates if they will allow us to interrupt them to a certain contract schedule, and we have something, roughly 700 megawatts of interruptible load which corresponds to giving us a benefit of about 2 per cent in reserve margin. That is what that 700 megawatts is worth.

The other factor is that we can turn to the interconnections for emergency purchases now. We believe that we will have available to us in the future about 700 megawatts of emergency purchases available during critical peak periods in our defined

contingencies, and I say that because the critical periods are usually at the peaks and we expect to have more in the way of interconnections available off-peak, up to 2,100 megawatts off-peak.

I would note that one of the contingencies we are designing for is the load forecast's being wrong here, causing us to go short.

Now, we have done studies of the errors that we make in load forecasting and the errors that other utilities make, and we are birds of a feather. We tend to overforecast and underforecast at the same time, so the term "load forecast error co-relation" means that, when we are having problems with our load forecast, they will.

Hence, the 700 megawatts is, in essence, a judgment made as to what we might get in the future when we are both suffering the same kinds of load forecast errors. That similarly has a value of, well, roughly 3 per cent.

Another emergency measure that is available to us is to reduce the voltage, and we make these tests periodically, incidentally, and we had thought initially that there would not be -- this was a free measure.

What we are starting to find is more and

more complaints coming in as we reduce our voltage. We believe that this will give us about another 3 per cent in an emergency situation.

Finally, the question of public appeals, to appeal to the public, to ask them to cut, and these cuts are imputed to be at little or no cost. And I mentioned earlier, whereas in the early '80s, we had thought something like 10 per cent might be available, now we believe we are looking at something more like 2 per cent.

So that in total, we expect to have emergency measures available in the future to deal with, roughly, to give us approximately a 10 per cent reserve margin benefit.

Q. Finally, the fourth box on page 32 references the reserve margin. Could you explain what you mean by that?

A. Now, we are looking at page 37 of Exhibit 136, and just pulling the results of our review of our experience together, that we had noted we can expect to face uncertainties of about 32 per cent, that we had relief of 10 per cent from emergency measures. The rest has to be handled by the reserve margin, 22 per cent.

So, what we have done to this point is,

our first test of our margin was by looking at other utilities; we said 21 per cent. This test of our own experience; 22 per cent.

Q. So, let's turn now to the third and final part of your review, then. What did your review of the data and the assumptions and the models show about the future reserve requirements of the existing system?

A. Our analytical review showed that margins of 20 to 24 per cent, we judge, bracketed the minimum total customer cost.

When we set up, there were reliability calculations. Our criteria of 25 system minutes was set in about 1981, in the early '80s, and what we do then periodically is check how much reserve margin that is equivalent to, and we do that over the years.

When we started the Demand/Supply Plan, we ran such a calculation and we got numbers in the range of 22 to 24 per cent. I had mentioned this earlier.

Now, with the completion of the Demand/Supply Plan, a number of significant things happened; one of which, we now knew what the final proposed Plan 15 was. We had earlier used some initial iterations of it, I guess you would call it.

One of the main features that came out was that through the '80s, we had assumed that our marginal generation would be a coal-fired plant, and we had variously attributed lead times of six to eight years to that coal-fired plant - and as I had mentioned to you, the further you forecast, the bigger your uncertainly is going to be - and in the development of the Demand/Supply Plan, we determined the CTUs were the best generation for peaking.

The major effect on that was to reduce the lead time that we had to plan for, for four years. What that led to was less in the way of load forecast uncertainly, so that would have meant a lower reserve margin.

Now, offsetting that is - and again, I have referred to this frequently - we reviewed our experience with emergency measures and we determined that there was not as much available, especially in public appeals, as we had determined.

The other thing that we did is, I mentioned also earlier that these models attempt to describe some of the things that can happen to you in emergencies. They do not purport to describe all of the things that can happen to you, and we had been doing work which allowed us to introduce an important

factor for us, called hydraulic energy limits; namely, that our hydraulic generation does not have enough water to run at full capacity for long periods of time.

That is an important factor in reliability, so that we did this final review with what we believe to be an improved model.

Q. What was the result of those updates to reliability?

A. I will refer you now to page 38 of Exhibit 136. Earlier, I had showed you a minimum total customer cost curve and I had mentioned that it had a very flat bottom.

This is a version of that, that is a little more precise in determining the minimum, but that is, in essence, what we did. What we found when we repeated the calculations was that the minimum total customer cost with our new assumptions occurred in the range of, say, 20 to 22 per cent.

And so, I had mentioned 21 for the utilities, 22 based on our experience, 20 to 22 based on our analysis.

Now, what this curve does is, as I have outlined to you in the calculating procedure, we picked some generation, we pick a demand to meet, we describe the uncertainties, we compute the unsupplied energy,

and then when we, having computed the unsupplied energy, we attribute a customer damage cost, which is roughly $6 per kilowatthour, and we compute the damage that the customer has.

We then go on the other side and we compute the cost of supply and we try and balance the two.

Now, what this curve shows is the benefit that is gained by moving from one reliability level to another, so the first calculation, say at - it is difficult to read - at something like a 19 or 20 per cent reserve margin, we then added four 150 megawatt, approximately, CTUs, which gives a benefit of about 2 per cent in reserve margin. We found that moving from 2 per cent reserve margin moved us down the curve approximately - I can't read it off too well this way - but moved us down the curve. The customer costs were reduced by that amount. And we did progressive calculations with more and more combustion turbine units and showed the benefit of moving down to progressively lower reserve margins. So, that is the reduction in customer damage cost that comes about from increasing reliability.

Now, the increase in reliability was obtained, as I mentioned, by adding combustion turbine

units, and in this form in the calculation, the cost of adding a combustion turbine unit is constant. We are adding increments of combustion turbine units worth 2 per cent in reserve.

Where those two lines cross gives you a very precise indication of where the minimum is. "Precise" is maybe not a... Yes, precise. Not accurate; precise. And it occurred in the range, as I say, of 20 to 22 per cent.

We did that calculation for the year 2000 and for the year 2005. The cross-over is less or -- well, is less at 2000 and more in 2005 because there is additional generation, immature generation in service with higher forced outage rates and increased energy limited hydraulic in place, and so the reserve margin increases slightly through that period.

What I have just mentioned is that this is the absolute minimum. It is none of the judgments being made about being to the left or right of the minimum.

Q. Mr. Taborek, you have taken us through quite a number of reliability issues and I wonder if you could sum up the key points for us?

A. I think there are six key points on reliability.

Systems must have a margin to deal with uncertainties in forecasts of demand and available generation.

The reserve margin requirements of the existing system and the DSP was based on a range of reserve margins. The range was from 20 to 24 per cent.

We checked the reserve margins used in the DSP very thoroughly by comparing with other utilities, by reviewing our own past experience and projecting it into a future circumstance, and by reviewing our models and data.

Having done that, I would judge that the range of 20 to 24 per cent reserve margin is about right for the existing system and for assessing additions to it.

...

[3:27 p.m.] I would judge a reserve margin of about 24 per cent to be a little on the more reliable side of the theoretical minimum total customer cost, but with a small added cost.

And I think there are good reasons for being on the more reliable side, because there is little extra cost and because, basically, you cannot describe all of the factors that are going to hit you. Analysis will always understate what a true minimum total customer cost would be. And that a reserve margin of 20 per cent for a utility with our characteristics is judged to be on the less reliable side of the minimum total customer cost theoretically.

There will be added risks of interruptions, and, once you are into a problem, it hits you hard and fast at our kind of utility, but that at that level to run that risk for brief periods of time is appropriate.

Q. Let's turn to a different subject. Mr. Snelson noted in his opening remarks that the capability of the existing system varies over time during the planning time frame, due to retirements of existing generation.

Would you describe for us the age of your existing generating units, beginning first with

hydraulic?

A. I will refer you to page 39 of Exhibit 136 which shows some statistics on the ages of our hydraulic fossil and nuclear units. The first generation in widespread use in Ontario was hydraulic, and our oldest hydraulic units at DeCew Falls were put in service in 1904, so they are 87 years old.

We have a lot of old, small plants. Later, we began to introduce larger new plants, Saunders, et cetera, and so the average age of our capacity is 37 years. The average age of our stations, if you will, is 57 years. Our newest hydraulic unit at Arnprior was put in service in 1977, and it's 14 years old.

Q. I note that you said that the average age was 57, but your chart says 37.

A. The 57 is if you just average the age of the stations; the 37 is if you average the age of the capacity, and that's because, latterly, we had had larger capacity in the stations.

Q. And turning now to your fossil units.

A. In post-war, the province was experiencing rapid load growth, no building in generation for some time, and again underforecasts in load, and there were brown-outs, widespread brown-outs.

The hydraulic stations had been intensively developed, and to get additional hydraulic stations into service was judged to take too long, and so the province turned to coal-fired generation. The Keith plant was built in a 3-year period, some Hearn units were built in a 3-year period to lift us out of the post-war problems that we had.

Beyond that, those two plants are now mothballed, and beyond that, we went into larger fossil units, much larger than those, at Lakeview, Lambton, Nanticoke, et cetera.

Our first major fossil units at Lakeview were put in service in 1962. They are about 29 years old now. The average age of our fossil capacity is 20 years and our newest fossil unit at Atikokan was put in service in 1984, so it's seven years old.

Q. And the age of your nuclear units?

A. The first nuclear units at Pickering were put in service in 1971. They are 20 years old. The average age of our nuclear capacity is 10 years. And our newest nuclear unit, Darlington, went into service in '90, and the last three units are scheduled to be in service in 1993.

Q. What is the expected life of your existing generating units?

A. The expected life of fossil and nuclear units is 40 years. Hydraulic units are expected to last indefinitely.

Q. What kinds of factors go into determining the life of units?

A. Generally four. One is that units wear out with use and age, and maintenance costs can become so high that it's more economic to replace a unit, even if it's with a unit of identical type than to repair it.

The second factor is that the technology can evolve. So that even if a unit runs normally, it can be more economic to replace it with a unit of the new type. Economic obsolescence.

Third, new environmental regulations may make it more economic to install a new unit rather than attempt to retrofit an old one to meet evolving environmental regulations.

And finally, of course, the existence of approvals to build new units has an impact on the life of the units that you will continue to run.

Q. How exactly do you go about determining the life of these units?

A. Periodically, we will do studies of the need for and the economics of a particular station

on the generating system. In addition to that, Hydro has a committee called the Depreciation Review Committee, who, basically, review the life of all of Hydro's assets.

This is a committee of senior technical and financial staff. They meet each year and basically what they do is they judge the operating experience of the asset over the time. They consider future developments and technology in the plans that Hydro has for use of the assets in light of the latest circumstances and, again, they compare their judgments with judgments made by other utilities.

Q. Are these judgments subject to any kind of a verification?

A. Yes, they are, in four ways.

First, the judgments are reviewed every year for validity. Second, they are reviewed by auditors for reasonableness. Third, they are reviewed periodically by financial consultants. And four, they are exposed to annual public review by the Ontario Energy Board because the service life impacts on depreciation costs and hence on electricity rates.

Q. Let's deal with the different types of generation, then, on the system beginning first with hydraulic. How well have the hydraulic stations

performed in the past and how well do you expect them to continue to perform in the future?

A. What I would like to do is give you an overview - and I will use page 40 of Exhibit 136 - which deals with the hydraulic system. And I will introduce you to a term "incapability." Incapability is as it says the inability to perform. This should be as low as possible. We have broken it into two categories: that which is forced on us, it comes by surprise; that which we can plan for which makes up then the total.

And the reverse of this, the capability of the units, is what allows us to produce the energy that we referred to earlier that comes from our different types of generation. And this is maintenance requirements.

The one, the lowest forced is what hits you on the reliability side. This is the one that you can't plan for and that causes your unavailable generation when you are expecting to have it. So this is an important parameter.

THE CHAIRMAN: I wonder if we can take the break now? Would that be convenient?

I realize it's sort of in the middle of something, but it will break the afternoon.

MRS. FORMUSA: Yes. That's fine. Thank you.

THE REGISTRAR: The hearing will recess for 15 minutes.

---Recess at 3:40 p.m.

...

---On resuming at 4:00 p.m.

THE REGISTRAR: Please come to order. This hearing is now resumed. Please be seated.

MRS. FORMUSA: Q. Mr. Taborek, you were at page 40 of Exhibit 136. Do you want to continue from where you left off, please?

MR. TABOREK: A. Yes. Page 40 shows the incapability of our units, roughly speaking, the time in which they are out for maintenance, broken down into forced and total. The forced plus that which you have more period to plan makes up the total. And it is the forced incapability, that which happens suddenly, that has an impact on your reliability planning and it is your total incapability that has an impact on your capacity and energy planning.

In looking at the hydraulic system, we have shown some historical information beginning in the mid-70s and a forecast.

Looking at the historical material, you will see evidence of a slight trend in increasing incapability. In the mid-'70s, the forced incapability was about 2 per cent; it is now rising to 4 and above.

The total incapability was perhaps in the 6 per cent range and it is now rising up to the 10 per cent range. We believe that to be evidence of aging

and requires additional maintenance to restore.

Q. Do you have any programs in place in order to maintain these hydraulic units?

A. Yes, we have five programs in addition to the normal maintenance.

We have a hydraulic unit overhaul program; a small hydraulic program where we assess the requirements of the small programs and retrofit as required; we have a turbine upgrade program to fit new modern, more efficient turbines; we have a process control improvement program to fit superior controls, improve controls, and we have a dam structure assessment program.

Now, these programs and the rehabilitation of hydraulic will be dealt with in more detail on further panels.

The point I would like to make is that we expect, over the next 10 years, to spend approximately $1-billion in OM&A and about $1.5-billion in capital to maintain the hydraulic units.

Q. You started out by saying that hydraulic units, you expect them, their service lives, to go on indefinitely, and I wonder if you could explain why their service lives are so different from those of thermal units?

A. Until recently, we had assigned a 70 to 90 year life to the hydraulic units. It was in doing the Demand/Supply Plan that we began to consider circumstances in which we might not continue to use that resource, and basically it's very difficult to think of circumstances where you would.

I think what we have is a resource that is low cost and renewable. We don't see any technology that would make it economic to replace the existing units. We don't see that it would not be economic to do the replacement, and the sites have been in existence for many years and removing them could cause as much in the way of environmental problems as maintaining them.

In the past, where we have given up stations, we have, generally, the experience in dealing with the public that is effected, we have been asked to maintain the water levels where they had been.

And so what we expect is that the sites will be maintained in perpetuity. What we have we will replace, maintain and replace, dams or maintain and replace units to keep them going, and the life is, in effect, not a station life but a component life.

Q. Turning now to the fossil generation, could you describe the performance of your fossil

units?

A. I would like to make a transition here and just call your attention to hydraulic before we go to fossil, because one of the things that isn't evident from this chart but which you will see when I put the fossil up, is what a low incapability the hydraulic units have and how reasonably smooth and predictable our experience with them has been. You will see this when I put the fossil on.

DR. CONNELL: Can I ask before you go on, are these units in energy?

MR. TABOREK: These are in percentages of capacity that are out of service.

DR. CONNELL: Peak capacity?

MR. TABOREK: Of the peak capacity that is out of service, yes.

DR. CONNELL: At any time during the year?

MR. TABOREK: Well, the forced out could happen at any time and the planned out would be scheduled into the most convenient times.

So, it's the forced out that we are concerned with. The peaks, we would try and do the planned maintenance in the off-peak periods, if at all possible.

The hydraulic and the nuclear units you will see are pretty well off the page compared to fossil, they have a much higher forced outage rate. And what you are seeing is a fairly smooth curve here because you have large numbers of small units with a long operating history and so they are more reliable as a result.

Turning to page 41 of Exhibit 136, we show our history and our forecast for our fossil generation. And the point I was making, the hydraulic charts was all below here. You see, only rarely do we manage to get the fossil into that area.

Looking at the history, you also see evidence of very wide swings. What is happening here is that you have a few units, if you had one unit, it is either in or out, it's either zero or a hundred in the time period, and you are gaining experience with new units so you are going through all the teething problems.

And you see in the '70s, roughly speaking, something in the 15 to 20 per cent range for forced outages and something in the 20 to 25 per cent range for total outages.

I mentioned to you earlier that when studies were done in the early '80s, they used quite

high forced outage rates. We have since adjusted them. You can see the '80s occur, roughly, here, so here was where the fossil system, I guess, basically got the hang of it, and we got the teething problems out. We improved the forced outage rate quite sharply, and that's a direct gain in being able to use a lower reserve margin, a more reliable system.

The same is true, very high total incapability in this period --

MRS. FORMUSA: Q. Sorry, that period is the '70s?

MR. TABOREK: A. In the period in the '70s, yes.

And then, what you notice is a gradual climb again in both the forced and the total incapability. We believe these to be evidence of the need for mid-life rehabilitation programs, and we have defined a number of programs that we expect will restore this growing incapability to the level shown here in the future.

Q. You mentioned programs, perhaps you could describe what programs you are planning in order to maintain the fossil units for their 4-year life?

A. Again, the fossil panel will go into this in depth.

I would note that Lakeview and Lambton alone have $2.3-billion allocated to them for their rehabilitation and for the fitments of scrubbers at Lambton to make them environmentally acceptable.

All stations have 30-million a year allocated for a life management program which is beyond the rehabilitation, and roughly $20-million a year of that is for life management at Nanticoke. We expect this money will help restore our historic levels of incapability.

Q. Finally, with respect to the nuclear units, could you describe how well the nuclear units have performed in the past?

A. I would refer you to page 42 of Exhibit 136. The experience is similar to fossil in many ways.

You see evidence of very erratic behaviour in the early days with a few new large units and with the learning problems. You see an improvement to better levels of forced outage rates in the 10 per cent range in the late '70s and early '80s, and total incapability in perhaps the 20 per cent range. And then, again, you begin to see perhaps evidence of growing mid-life wear. And again, our forecast is that we will put programs in place that will restore the

capability of that system to those forecast levels in the time shown.

Q. And what kinds of programs do you have in place for the nuclear units?

A. Essentially, rehabilitation programs and retubing programs for the nuclear units.

We have already defined approximately a billion dollars of rehabilitation and retubing for the Pickering "A" station, and approximately $2-billion in rehabilitation and retubing is being considered for the Bruce station, Bruce "A." Pickering "A" and Bruce "A," in both cases.

Programs for the "B" stations will be defined at an appropriate time.

In addition, we have increased our normal maintenance programs. The OM&A costs have increased by roughly 58 per cent from 1988 to 1990, and close to 1,000 extra staff has been hired, most of whom have been allocated to the Bruce plant.

Q. You have noted what you expect the future performance to be, then, on that chart.

A. Yes.

Q. Could you explain why you plan to maintain the performance of the generating capacity you have for the remainder of their service lives?

A. Because it is usually more economic to maintain them than to replace them with new units. That's because it maximizes the benefit of the investment in the existing assets. And that, incidentally, was one the key elements in our demand/supply strategy that we developed, to maximize the use of the existing system.

Q. Why not plan on keeping the existing units longer than their currently forecast service lives?

A. Well, one of the things we have done is we have an increased the lives of all of our hydraulic, nuclear, fossil units over time, as the evidence emerged that it was appropriate to do so.

I mentioned to you that our hydraulic stations until recently had lives of 70 to 90 years and we feel, on balance, that it is now appropriate to consider them being replaced, component by component.

The fossil stations were originally designed on the basis of a 30-year life. In 1981, the Lambton and Nanticoke units were increased to a 35-year life, and in 1989, all the units were increased to a 40-year life.

On the nuclear system, the "A" stations were originally designed to a 30-year life, the "B"

stations were originally designed to a 40-year life. And in 1982, all of the nuclear stations had their lives increased to 40 years.

Now, we do not believe that it's appropriate to plan on the basis of a longer life than that. It would be exceedingly risky to do so. We have done some investigation of other utilities' practices and we tend to find, very frequently, lives less than we are using.

There is little or no experience with the operation of modern, high pressure fossil plants and nuclear plants for long periods of time. We basically don't know that they can be economically maintained for more than 40 years.

We are focusing our attention now in attempting to determine whether or not we can get them to last for 40 years. There is a high degree of controversy and uncertainty in that, and going beyond, you are taking one further step into the unknown.

...

[4:17 p.m.] Now, if you sort of put some common sense to work when you are predicting that on the average something will last for 40 years, say, chances are that some will last longer and some will not last that long.

What we face here is the fact that prudent planning should allow for the possibility of some of the lives being longer, but that one should not bet the mortgage on it.

We should plan on that basis as a prudent long life, and if, as time goes on in future and decisions are made, we should have the capability to introduce new generation if the expected comes about; i.e., the 40-year life on average, and that if the expected does not come about, and fortuitously, they can last longer, then one is in a position to be able to defer the introduction of the new to utilize the older for longer, but one is in a prudent position.

And, of course, on the other hand, in judging the possibility of longer lives there is also the possibility that lives can be shorter than that, and that also has to be taken into account.

So that the question of whether or not we can decide that the lives should be longer is not a judgment that we could make now. We do not know what environmental rules we will have to meet in future. We

basically have been hit with a new set of environmental rules roughly every two years during the 1980s. We expect more.

We do not know what the wear will be. We do not know what the various requirements will be, what alternatives will be available for us, and so what we are looking at is, I don't think there is anybody who can lay down the law that the life will be so-and-so.

What we are facing is, how can we put ourselves into a position to react prudently in the face of the uncertainty that exists with respect to it, and I would recommend to you a life of 40 years as a reasonable long life for the units for planning purposes.

Q. So I take it, then, that that was the criterion with respect to retirement that was used in the Demand/Supply Plan?

A. Yes. Each fossil and nuclear unit was retired when it reached its 40th birthday.

Q. How many retirements are expected in the 23 years from now to the end of the DSP planning time frame in 2014?

A. A total of 8,700 megawatts of fossil and nuclear generation would be retired. This is roughly 28 per cent of our existing capacity. These

would be the fossil units at Thunder Bay, Lakeview, Lambton, and some of the Nanticoke units, totalling 6,650 megawatts and --

THE CHAIRMAN: Sorry. Give me that figure again, please?

MR. TABOREK: 6,650 megawatts of fossil.

THE CHAIRMAN: Thank you.

MR. TABOREK: And nuclear units at Pickering totalling 2,060 megawatts, for a total of 8,700 megawatts, 28 per cent of our existing capacity.

MRS. FORMUSA: Q. In conclusion, Mr. Taborek, perhaps I am going to ask you to do the impossible, but I would like you to pull together much of the material that you have discussed this afternoon - about capacity and energy, the system reserve margin, age and retirement of existing generation - with how they define the load and energy and incapability of the existing system. Perhaps you could deal with the system's load-meeting capability?

MR. TABOREK: A. For reliability, you need more than 1 megawatt of generation to meet 1 megawatt of forecast load; the difference is the reserve.

Looking at 43 of Exhibit 136, the 32,500 megawatts of capacity we expect to have in 1993 will

Capacity

have the ability to meet 26,200 megawatts of load with a 24 per cent reserve margin. 6,200 megawatts is the reserve, the load-meeting capability.

From now on through succeeding panels, you will find load-meeting capability of the capacity used increasingly, rather than the actual megawatts of the capacity, where load and capacity comparisons have to be made.

Q. Okay. Then what is the future load-meeting capability of the existing system?

A. The effect of allowing for a 24 per cent margin is shown. Darlington coming on-line brings the load-meeting capability to 26,200, as I mentioned. With Darlington in service, the load-meeting capability stays essentially level to about 2006, and then with retirements, steadily decreases as major generating units reach the end of their lives.

Q. If we turn now to concept of energy, what is the energy-meeting capability of the existing system?

A. Page 44 of Exhibit 136 illustrates energy-meeting capability. We have mentioned that units cannot operate at full capacity 24 hours every day of the year. One has to allow for the maintenance of the system, the amount of water available in the

hydraulic system, demand patterns, acid gas and other environmental control requirements.

With those allowances, one can make a forecast of the energy-meeting capability of the existing system.

In 1989, the energy-meeting capability of the system was about 150 terawatthours.

The addition of the Darlington units adds about 24 terawatthours, but stricter environmental controls coming into place in 1994 restrict that, the energy production capability by about 9 terawatthours, so that by the mid '90s, the capability is about 165 terawatthours.

Beyond 2002, the capability gradually declines and then increasingly so, as more and more fossil units are retired.

Q. Thank you, Mr. Taborek.

Turning back now to Mr. Snelson, we have had an estimate of the capability of the existing system and I would like you now to describe how the load-meeting capability of that system compares to the basic load forecast that was presented in Panel 1.

First, could you tell us what range of loads is the Demand/Supply Plan designed to meet?

MR. SNELSON: A. I think we are at a

significant turning point here. We are moving from Chapter 4 of Exhibit 3 into Chapter 5, which should be recorded, perhaps.

If I can have the figure which is Figure 45 of Exhibit 136, I believe. This shows a range of load forecasts, of basic load forecasts which is extracted from the information provided by Panel 1.

Just to be absolutely clear as to what we have included here, the upper and lower bands of this range are as they are in Exhibit 3, as they were forecast to be at the time the Demand/Supply Plan was prepared, so that is not the latest load forecast range. That is as it was at the time the plan was prepared.

The median line in this range is the median of the current long-range load forecast that was prepared in December of last year. So, this is the range to which we are planning.

Q. Why has the range not been changed to reflect the December 1990 forecast?

A. When we prepared the Demand/Supply Plan, we fully expected that the median estimate would vary from time to time, but we wanted to introduce some stability into our long-term plans and long-term planning processes, and so we judged that we could stay

with the same range for the plan, provided the median stays well within the band and that we didn't have to adjust the range to which we planned each and every time the load forecast changed.

Q. How does the new median load forecast compare to the load-meeting capability of the existing system?

A. This is an update to Figure 5-1 of Exhibit 3 and it is page 46 of Exhibit 136.

It shows as the bottom line the load-meeting capability of the existing system as it has been described by Mr. Taborek in one of his preceding figures, I believe page 43 of Exhibit 136.

This shows that we will require some form of demand-reducing or supply-increasing option by the early 1990s, approximately 1993, and that the need grows quite substantially throughout the planning period, until a very large amount is required, of the order of 25,000 megawatts by the end of the planning period.

Q. What does the comparison look like with the upper load forecast?

A. The upper load forecast figure is shown here, which shows --

Q. Sorry. This is page...?

A. Sorry. This is page 47 of Exhibit 136, which is an update to Figure 5-2 of the Demand/Supply Plan Report.

I believe the point that is most significant on this figure is that seeing as the load forecast line has not changed and the adjustments to the capability of the existing system are very small, this is almost identical to the figure that is in the plan report.

Q. And what about the comparison with the lower load growths?

A. Similarly, with the lower load forecast, there is very little change from the plan report and that is shown on page 48 of Exhibit 136, which is an update to Figure 5-3 of the Demand/Supply Plan forecast, Exhibit 3.

Q. How much in the way of demand management or supply measures would be needed to fill the gap that you have identified on those figures?

A. The figure which is page 49 of Exhibit 136 is an update to Figure 5-4, and it shows the requirements; that is, the difference between the load forecast line and the load-meeting capability line from the previous three figures.

It shows those differences tabulated in

terms of gigawatts or thousands of megawatts. And this shows the increase that I talked about to about 25,000 megawatts' requirement by the end of the planning period.

It should be recognized that this is in terms of load-meeting capability, so if this need is met by generation, there will be additional amounts required for reserve margin.

Also, this does not take into account the existing demand management or existing non-utility generation that is already in place, so to that degree, it slightly overstates the requirement.

It was done this way because the demand management and non-utility generation will be discussed by subsequent panels.

Q. And what does the comparison look like on an energy capability and demand basis?

...

[4:31 p.m.] A. Again, page 50 of Exhibit 136 is an update to figure 5-6 of Exhibit 3, and the picture it shows is very similar to the one that is in the previous -- the one that was in Exhibit 3.

There is a slight increase in the requirement towards the end of the planning period. The increase starts around the late 2000s and becomes noticeable about 2010, and there is a slight increase of about 98 terawatthours. Do I mean 98 terawatthours? I don't think I do. Sorry.

The increase by 2014 is from 98 terawatthours to 109 terawatthours. That is the difference between the load forecast line and the capability line. So there is a small increase by the year 2014.

Q. Do you want to take us to page 51 of Exhibit 136?

A. Yes. Page 51 is a tabulation of the numbers I have just been discussing. And this is the figure that shows the upper, lower and median energy requirement in terawatthours. This is the difference between the load forecast line and the energy capability line.

The upper and lower columns are almost identical to the figure, corresponding figure in

Exhibit 3, which is Figure 5-9. On the median load forecast, the numbers are almost identical up to 2005. In 2010, the current number is 78 compared to a previous number of 70. And in 2014 the current number is 109 compared to a previous number of 98.

Q. Finally, how does the requirement for new options compare with that in the plan report?

A. I am now going back to a capacity basis instead of an energy basis. This is the comparison of the figures that are in the old 5-4 - when I say "this," this is Figure 52 from Exhibit 136 - is a comparison of the Figure 5-4 that is in Exhibit 3, with the revised Figure 5-4, which, I believe, was my Table 49 in Exhibit 136. The new numbers are shown plain and the old numbers are shown in brackets.

And on a capacity basis, you can see that the lower and upper requirements have changed very little, if at all, and that the median requirements have increased a little, particularly towards the end of the planning period. This indicates that for the rest of the Demand/Supply Plan that we are presenting, that the range that we are planning to now is almost identical to the range that we were planning to at the time of the Demand/Supply Plan preparation.

The effect of a change in the median load

forecast is that we now believe the median load forecast to be a little higher than the probability in that range, a little higher in that range, than at the time that we prepared the plan. At the time we prepared the plan, the median load forecast was about the middle of the range. Now, particularly at the very end of the planning period, the median load forecast is towards the higher end of that band, but still within it.

MRS. FORMUSA: Thank you. Those conclude my questions for Panel 2, Mr. Chairman.

THE CHAIRMAN: Thank you.

DR. CONNELL: I would like to ask two or three fairly basic questions of a technical nature, which might well come up later, but I think it would be helpful to me to have some grasp at this point. I am not sure who to direct this to, but probably any one of you could cope with it.

When you tell me that a particular generator has capacity of, say, 300 megawatts, is that based on rating or actual measurement? Is it a design specification or do you actually measure the output?

MR. SNELSON: It is based originally on a design specification, and once the unit is in service, it is based on measurement.

DR. CONNELL: Exactly how do you measure it, just in general terms?

MR. SNELSON: I haven't actually done one. I believe that they run the unit and they measure the amount of electricity that it produces when you are putting as much fuel into the boiler as it will take. But it also has to meet acceptable pressures and temperatures within the steam system so that they are not exceeded.

And, in fact, there are two definitions of capacity. One is a definition that can be sustained indefinitely, which is called the "maximum continuous rating" and there is another definition of capacity which is one that can be maintained for a short period of time, perhaps by going to a slight over-pressure on the steam system, perhaps by some other adjustments that can't be sustained for a long period of time, which is called the "dependable peak capacity." And our reliability planning is based on the dependable peak capacity of the unit.

DR. CONNELL: Are the measurements reproducible and reliable?

MR. SNELSON: Yes, I believe so.

MR. BARRIE: Operationally, the output of all the major units are being monitored constantly. So

when we ask for full load from a generating unit, we are measuring how many megawatts we are getting out of that unit all the time, so we can operationally constantly be updating what we can count on from that unit from some measurement that has only just been taken.

DR. CONNELL: What would be the typical variation in understanding operating conditions for, say, one of the coal-fired thermal units? Just an order of magnitude. 5 per cent?

MR. BARRIE: A 500-megawatt unit would normally be operating much closer than that. We would expect to get very close to 500 megawatts. However, there are certain instances when we do not. I think I indicated in my evidence some circumstances when we are having problems and we had to derate machines. So it would be the derated amount that we use operationally, until it proves that it can get back to the maximum continuous rating that we normally expect.

DR.CONNELL: Comparing design to performance, is it, in fact, possible to design and get performance which corresponds accurately to your forecast capacity? If you are aiming for 500 megawatts, is that, in fact, what you will get normally?

MR. BARRIE: Yes. As Mr. Snelson mentioned, we will often get -- we can get more than that. There are overload capability for all of the major 500-megawatt units. Nanticoke and Lambton in particular can give us several megawatts over and above the 500 for specified periods for a number of hours. In the case of Nanticoke, it's about 540 megawatts.

DR. CONNELL: One of you - it may have been you, Mr. Barrie - you were describing the impact of overload on a generator. You said, I think, that the generator might in fact slow down.

MR. BARRIE: That wasn't me, but I will take over, if you will.

The generators are all connected together. They are all operating at exactly the same speed, at synchronous speed. The only thing that will cause them to slow down, as long as they are all connected together, is if there is too much requirement on the system as a whole; and by that I mean the whole interconnection, the whole northeastern -- the whole eastern interconnection.

If that were to happen, what would happen was the system frequency would start to fall. Mr. Taborek mentioned that if he didn't do anything about that, the frequency would fall to the point that the

generators would get into areas they are not designed to operate in. But before that happens, there is protection on the generating units which will actually trip the generating units off. The system will start to break up in fact.

DR. CONNELL: Would this happen within 1 per cent of the change in cycle or even closer than that?

MR. BARRIE: Long before that happens. When the frequency starts to fall, the first thing that happens is we have automatic disconnection of load.

DR. CONNELL: Yes.

MR. BARRIE: We will disconnect load in order to maintain the system as a whole. We have what's called "frequency trend relays," which are sensing the frequency all over the system and will disconnect load. That's if the operator hasn't previously done it manually anyway. When he sees this situation arising, he would initiate that kind of event.

DR. CONNELL: Just roughly, what magnitude of system overload are you talking about then?

MR. SNELSON: In terms of frequency, the frequency trend relays will cut in at about 59 cycles

and this is a 60-cycle system. The generating units would be in mechanical troubles that Mr. Taborek described at about 58 cycles, so it is quite a small band.

And the amount of load that would cause a drop in frequency depends on how long it is sustained. The balance is that there is a certain amount of energy being withdrawn from the system by the people who use electricity, and there is a certain amount of fuel being put into the boilers of all the generating units of falling water; and provided that is in balance, then the frequency remains the same.

If the load exceeds the amount of fuel, then the energy has to come from somewhere and it comes from the rotational energy of the machines, and all of machines together will start to slow down. And this phenomenon would be quite slow if the excess load is quite small. If it was in a disconnected part of the system because of a transmission failure that found itself with a large excessive generation compared to -- a large excessive load, sorry, compared to the generation that was in this isolated area, then it would be very fast.

DR. CONNELL: This prompts me to ask another question which I have never been able to

understand. Can I just ask: Is it extremely difficult to manage the phase? Particularly when you are starting up a generator, how do you get it in phase with the rest of the system?

MR. BARRIE: A unit is brought up to speed, synchronous speed, by its own boiler and turbine unit, brings the generating unit up to speed. When speed is approximately equal to the system speed, the operator has what is called a "synchroscope" which is measuring the speed and phase of the generating unit and the same for the system. And when they are at the same speed and in phase, he will close the circuit breaker. It's a routine task that is done many, many times a day.

DR. CONNELL: So the load isn't applied until --

MR. BARRIE: No, there is no load. When you close a circuit breaker, there is no load on the machine. A certain amount of steam has to be supplied to get the machine rotating at that speed, but there is no actual electrical output at the instant you close.

Now there quickly is load applied because it's more stable to get load onto the machine quickly, but at the instant the quota takes place, there is no load.

DR. CONNELL: Can you explain to me from your transmission diagram for the bulk system, if you take Bruce, for example, it's linked in by two different routes.

MR. BARRIE: More than two, several.

DR. CONNELL: Yes.

So, all the power from Bruce would have to be in phase no matter by what route it got to its destination.

MR. BARRIE: Yes.

DR. CONNELL: Say it came to Milton, by whatever pathway, it would have to all be in phase at the same time; is that correct?

MR. BARRIE: Yes. The way one expresses that is that there is a vector relationship between the power at any points in the system; and between Bruce and Milton, as you put it, however the power gets there, it has to obey that relationship.

DR. CONNELL: This is part of the design of the transmission system as well?

MR. BARRIE: Yes. The most direct route has the lowest impedance from point A to point B, most of the power will flow down that direct route, so I showed Bruce to Milton as being the most direct. Most of the power will flow in that. But there will be

power flowing on the other circuits inversely proportionate to the impedance of the circuits.

There are now two 500 kV circuits by the way. That was the situation as existed last year.

DR. CONNELL: In parallel, yes.

MR. BARRIE: Yes. So we now have two. Another circuit was commissioned in November 1990 that takes power down to the London area.

DR. CONNELL: Could you give me some impression of the difference between a 60-minute peak and a 20-minute peak and an instantaneous peak in let's say a typical day. Do you get instantaneous peaks that are quite a lot higher than the 20-minute peak or the 60-minute peak?

...

[4:50 p.m.] MR. BARRIE: I am not sure what the exact percentage is.

MR. SNELSON: I don't have an exact percentage. It's quite small.

MR. BARRIE: Certainly, between the peak and the 20 minute is very small, yes.

MR. SNELSON: We have data, certainly 20 minute peaks and one hour peaks, and I believe the load forecast is specified in either way.

DR. CONNELL: And when you are doing your planning, which is the normal focus? Which do you normally use when you are looking at peak capacity in planning, or do you have to look at all three?

MR. BARRIE: The 20-minute peak is certainly enough for the operational type planning we do. I am not sure about the longer term planning.

MR. SNELSON: I am not sure what we got in our latest simulation. I believe that the load and capacity table that reports reserve, does so on a 20 minute peak basis.

DR. CONNELL: In circumstances where the supply exceeds the load, I presume you will fairly quickly shut down, but for a short interval what happens to the excess? How do you dump load?

MR. BARRIE: The reverse happens from the

situation we described earlier.

On a system-wide basis, if there is excess generation, the frequency will start to increase. That will be sensed. It's sensed both automatically, there are governors on the machines, will sense that there is an increase in frequency and will reduce the generation output so that will automatically correct it. If that wasn't done, then operators would physically reduce the generation so that a match was achieved again.

I should say, though, that because we are part of the North American interconnection, the system frequency is extremely stable. These phenomena I have been discussing would be very rare occurrences in North America.

You have got to put the loss of one 500 megawatt machine in the context of a 400,000 megawatt system. So it is a very, very small drop. On an isolated system, the frequency control is much more difficult.

DR. CONNELL: But what happens, say -- let me postulate some catastrophic circumstances, a tornado comes along and blows down a transmission line and you have got the whole load from Bruce "A" and Bruce "B" instantaneously interrupted. What happens?

MR. BARRIE: Well, that particular tornado in 1985, when that took down the transmission, we suddenly had a tremendous excess of generation in the Bruce area, we have an automatic scheme which removes generation instantaneously should that occur, it's called the Bruce load and generation rejection scheme.

I believe I quoted 3,000 megawatts. That's four Bruce units being instantaneously disconnected from the system to remove that excess capacity in that particular area.

DR. CONNELL: But the reactor keeps on operating at fairly high power for a transitional period?

MR. BARRIE: Yes.

DR. CONNELL: So that must be tremendous heat dissipation?

MR. BARRIE: Yes, steam is being dumped, in fact. You have to dump steam because the reactor, as you say, will continue to produce heat for some time after that.

MR. SNELSON: I believe it goes down quite quickly to about 1/10th of its power.

DR. CONNELL: You mean in a matter of seconds?

MR. SNELSON: Minutes. But this is the sort of control question that would perhaps be better put to Panel 9 on nuclear.

The issue from a system point of view is that every generating unit, whether it's hydraulic, nuclear or fossil, must be able to withstand what we call a full load rejection. It's one of its basic design parameters, is that it has to be able to withstand the opening of the switch that connects it to the power system so that it instantaneously loses all its load, and it has to have sufficient controls and other mechanisms that it prevents any damage to the unit in that circumstance, and that's a primary design requirement for all generation.

DR. CONNELL: With regard to the environmental issues that Ms. Ryan discussed, you didn't bring up any of the issues related to either mining at one end of the fuel cycle, nor to decommissioning of plants at the other end. Are those matters that we will be looking into with another panel?

MS. RYAN: I believe the fossil or nuclear panels will be prepared to address that.

I think, historically, on the mining end, we, as a company, haven't done that much, but certainly

Panel 9 and the used fuel plan that has been prepared would be prepared to address that.

On the decommissioning end, we are required to have decommissioning plans in place and, again, the specific option panels would be prepared to discuss that.

DR. CONNELL: And with respect to some of the details of the issues you raised, the issue of particulate measurements, radioactive effluents and so on, are those a matters that will be dealt with in more detail later?

MS. RYAN: That was the plan. From a general overview, I can cover that. But if you want specific details on the detail of monitoring requirements or control of equipment specifications, then that would be dealt with at the option panel stage.

DR. CONNELL: Perhaps I could just mention one particular point of information that interests me that we might come back to later, and that simply concerns the nature of used fuel. I would like to have a picture of the composition of used fuel, both in terms of content of specific isotopes, their half lives and their radioactivity; that is, their magnitude in curies or whatever units, compared to that of the

original fuel bundle as it went in.

MS. RYAN: Okay. I am not in a position to do that right now.

DR. CONNELL: No, I understand that. That's a rather complicated question.

MS. RYAN: But I would certainly think the people on Panel 9 would have that information.

DR. CONNELL: Right. And then to have a profile of the waste every, perhaps, one year, 10 years, 100 years, 1,000 years.

MS. RYAN: Yes, okay. The amount of radioactivity as it decays?

DR. CONNELL: Yes.

With respect to the particular uses of ash, both flyash, which you said was being used in concrete, and the solid ash, which is being used in roads--

MS. RYAN: Yes.

DR. CONNELL: --is anything known about the leaching of metals or other contaminants from those materials?

MS. RYAN: Yes. We do leach tests for our ash. Right now, ash is not classified as a hazardous substance under the Environmental Protection Act, but we are required to do leachate tests to

determine that in fact that is the case. And so that information does exist for tests that have been done.

DR. CONNELL: We might look at that later then, too.

Generally, with respect to the radiation standards, the AECB standards and your own internal standards, which I understand are better than one per cent of the AECB standards, have you any indication that the standards are shortly to be lowered?

MS. RYAN: My understanding is that there are discussions underway, and they will likely be lowered in the next year to two years, yes.

DR. CONNELL: Are you planning to adapt, in turn, if AECB changes -- will Hydro likely also change in parallel?

MS. RYAN: Whether or not we would maintain the 1 per cent of the regulatory limit, I don't know, but we would certainly still be well under a new limit, and I believe there are plans in place to see what the new limits would mean from an operations point of view and what options are available to control our emissions further.

DR. CONNELL: I think those are the main things.

---Off the record discussion.

MS. PATTERSON: I just have a couple of questions.

Mr. Taborek, did you say 1,000 extra staff were hired?

MR. TABOREK: Yes.

MS. PATTERSON: And they were allocated to the Bruce plant?

MR. TABOREK: Mostly to Bruce.

MS. PATTERSON: On page 44, Energy-Meeting Capability, Existing System, you lost me when you talked about something in the year 2000.

MR. TABOREK: Beyond 2002, the units begin to retire and so the energy capability decreases, slowly at first, because some of them are peaking units and, then, more rapidly, as units that work more retire.

MS. PATTERSON: I guess I just didn't understand it because the line continues to be straight.

MR. TABOREK: It's very shallow. It's small initially, and then it increases.

MS. PATTERSON: Thank you.

MR. TABOREK: Peakers don't produce much energy, capacity doesn't produce much energy, is the simple explanation.

MS. PATTERSON: Thank you.

THE CHAIRMAN: Mr. Watson, you will be starting with MEA tomorrow?

MR. WATSON: Yes, Mr. Chairman.

THE CHAIRMAN: How long do you expect to be, do you have any idea?

MR. WATSON: I have some difficulty with this panel because of the nature of it, with the number of the issues being relevant not only this panel but later panels, but my best estimate now is I will be at least all day tomorrow.

THE CHAIRMAN: You might try to resolve some of those with Mrs. Formusa beforehand.

MR. WATSON: That's been an ongoing process for some time, Mr. Chairman.

THE CHAIRMAN: I see, all right.

Mr. Rodger, you will be next, is that right?

MR. RODGER: Yes. I expect I will be a full day.

THE CHAIRMAN: That seems to take us to Thursday.

Energy Probe? Anybody here from Energy Probe?

No one here from Energy Probe today.

And then Mr. Shepherd, you will follow Energy Probe?

MR. SHEPHERD: Yes.

THE CHAIRMAN: All right. We will adjourn until tomorrow morning at ten o'clock.

---Whereupon the hearing was adjourned at 5:02 p.m., to be resumed on Wednesday, May 22, 1991, at 10:00 a.m.